Hilcorp Alaska, LLC

December 4, 2023

Sent via Email

Alaska Department of Environmental Conservation Air Permits Program
Attn: Air Permit Application Intake Clerk
555 Cordova Street
Anchorage, AK 99501
dec.aq.airreports@alaska.gov

Subject: **Grayling Platform Fuel Gas H_2S Increase Project**
Construction Permit Applications under 18 AAC 50.306 and 18 AAC 50.508(6)

Dear Sir or Madam:

Hilcorp Alaska, LLC (Hilcorp) hereby submits this application under Alaska Department of Environmental Conservation (ADEC) Air Quality Control Regulations at 18 AAC 50.306 (Prevention of Significant Deterioration [PSD] and 18 AAC 50.508(6) (Revising or Rescinding Terms and Conditions of a Title I Permit) for the Grayling Platform Fuel Gas H_2S Increase Project. The Alaska Department of Environmental Conservation (ADEC) issued a minor source permit to Hilcorp on February 14, 2019 (AQ0069MSS04) for the Grayling Platform to protect ambient air quality by establishing a limit on the hydrogen sulfide (H_2S) content to 400 parts per million by volume (ppmv), monthly average. With this application Hilcorp requests an increase of the permitted short-term (i.e., monthly average) fuel gas H_2S limit to 1,250 ppmv to protect ambient air quality and proposes to establish a Best Available Control Technology (BACT) limit of 98 tons per year (tpy) of sulfur dioxide (SO_2) emissions based on an annual average fuel gas H_2S concentration of 650 ppmv.

The application contains the information required under 18 AAC 50.306(b) and 18 AAC 50.540(a), (b), and (k), which is presented as attachments to this letter as follows:

- Attachment A – Project Identification Form
    - Attachment A-1 – Additional Application Requirements for Sources within the Regional Haze Special Protection Area
    - Attachment A-2 – Criteria Pollutant Emissions Calculations (electronically enclosed)
- Attachment B – Project Description, Emissions and Regulatory Review
- Attachment C – SO_2 Best Available Control Technology (BACT)
- Attachment D – Permit Revisions Request (18 AAC 50.508(6))
- Attachment E – Demonstration of Compliance with State Emissions Standards
- Attachment F – Ambient Air Quality Impact Assessment (AQIA)
- Attachment G – Copy of Permit No. AQ0069MSS04

If you have any questions or require additional information regarding this application, please contact Drew Anderson at 907.777.8488 or anandersen@hilcorp.com.

Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

Sincerely,

Trudi Hallett

Trudi Hallett
Asset Team Lead
Hilcorp Alaska, LLC

Electronic cc: Sims Duggins (SLR International Corporation)
Jesse Jack (ADEC)
Grace Germaine (ADEC)
Jim Plosay (ADEC)

Enclosures: as stated

Grayling Platform

Fuel Gas H_2S Increase Project Construction Permit Application

Attachment A – Project Identification Form

Hilcorp Alaska, LLC

3800 Centerpoint Drive, Suite 1400, Anchorage, AK 99503

Prepared by:

SLR International Corporation

2700 Gambell Street, Suite 200, Anchorage, Alaska, 99503

SLR Project No.: 105.00874.20026

October 2023

Making Sustainability Happen

Alaska Department of Environmental Conservation
AIR QUALITY CONSTRUCTION PERMIT APPLICATION
Attachment A
Project Identification Form

Section 1 Stationary Source Information

Stationary Source Name: Grayling Platform			SIC: 1311
Project Name (if different): Fuel Gas H_2S Increase	Stationary Source Contact: Drew Anderson		
Source Physical Address: Cook Inlet, Alaska	City: Anchorage	State: AK	Zip: 99503
	Telephone: (907) 777-8488 E-Mail Address: ananderson@hilcorp.com		
UTM Coordinates (m) or Latitude/Longitude:	Northing: N/A	Easting: N/A	Zone:
	Latitude: 60° 50' 23" N	Longitude: 151° 36' 47" W	

Section 2 Legal Owner

Name: Hilcorp Alaska, LLC		
Mailing Address: 3800 Centerpoint Drive, Suite 1400		
City: Anchorage	State: AK	Zip: 99503
Telephone: 907-777-8300		
E-Mail Address: N/A		

Section 3 Operator *(if different from owner)*

Name: Same as **Legal Owner**		
Mailing Address:		
City:	State:	Zip:
Telephone:		
E-Mail Address:		

Section 4 Designated Agent *(for service of process)*

Name: CT Corporation System		
Mailing Address: 9360 Glacier Highway, Suite 202		
City: Juneau	State: AK	Zip: 99801
Physical Address: Same as **Mailing Address**		
City:	State:	Zip:
Telephone :		
E-Mail Address:		

Section 5 Billing Contact Person *(if different from owner)*

Name: Hilcorp Alaska, LLC Accounts Payable		
Mailing Address: PO Box 61529		
City: Houston	State: TX	Zip: 77208
Telephone: (907) 777-8300		
E-Mail Address: N/A		

Section 6 Application Contact

Name: Drew Anderson			
Mailing Address: 3800 Centerpoint Drive, Suite 1400	City: Anchorage	State: AK	Zip: 99503
	Telephone: (907) 777-8488		
	E-Mail Address: ananderson@hilcorp.com		

Section 7 Major Permit Classification(s)
(Check all that apply)

- ☒ 18 AAC 50.306
- ☐ 18 AAC 50.311
- ☐ 18 AAC 50.316

Section 8 Minor Permit Classification(s)
(Check all that apply)

- ☐ 18 AAC 50.502(b)(1)
- ☐ 18 AAC 50.502(b)(2)
- ☐ 18 AAC 50.502(b)(3)
- ☐ 18 AAC 50.502(b)(4)
- ☐ 18 AAC 50.502(b)(5)
- ☐ 18 AAC 50.502(b)(6)
- ☐ 18 AAC 50.502(c)(2)(A)
- ☐ 18 AAC 50.502(c)(2)(B)
- ☐ 18 AAC 50.502(c)(3)
- ☐ 18 AAC 50.508(3)
- ☐ 18 AAC 50.508(5)
- ☒ 18 AAC 50.508(6)

Section 9 Project Description

Provide/attach a short narrative describing the project. Discuss the purpose for conducting this project, what emission units/activities will be added/modified under this project (i.e., project scope), and the project timeline. If the project is a modification to an existing stationary source, describe how this project will affect the existing process. Include any other discussion that may assist the Department in understanding your project or processing your application. Include a schedule of construction and the desired date for permit issuance.

If this application includes an Owner Requested Limit or a request to revise an existing permit term or condition, describe the intent of the limit, and provide sample language for the limit, and for monitoring, record keeping, and reporting for showing compliance with the limit.

Add additional pages if necessary.

See **Attachment B** for Project Description

Section 10 Certification

This certification applies to the Air Quality Control Construction Permit Application for the Grayling Platform (Stationary Source Name)
submitted to the Department on: 12/4/2023

Type of Application

☒ Initial Application
☐ Change to Initial Application

The application is **NOT** complete unless the certification of truth, accuracy, and completeness on this form bears the **signature of a responsible official** of the firm making the application. (18 AAC 50.205)

CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS

"Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete."

Signature:	Date: 12/4/2023
Printed Name: Trudi Hallet	Title: Asset Team Lead

Section 11 Attachments

☒ Attachments Included. List attachments:

Attachment A – Project Identification Form
Attachment A-1 – Additional Application Requirements for Sources within the Regional Haze Special Protection Area
Attachment A-2 – Criteria Pollutant Emissions Calculations (electronically enclosed)
Attachment B – Project Description, Emissions and Regulatory Review
Attachment C – SO_2 Best Available Control Technology (BACT)
Attachment D – Permit Revisions Request (18 AAC 50.508(6))
Attachment E – Demonstration of Compliance with State Emissions Standards
Attachment F – Ambient Air Quality Impact Assessment (AQIA)
Attachment G – Copy of Permit No. AQ0069MSS04, Revision 1

Section 12 Mailing Address

Submit the construction permit application to the Permit Intake Clerk in the Department's Anchorage office. Submitting to a different office will delay processing. The mailing address and phone number for the Anchorage office is:

Permit Intake Clerk
Alaska Department of Environmental Conservation
Air Permit Program
555 Cordova Street
Anchorage, Alaska 99501
(907) 269-3070

Attachment A-1

Additional Application Requirements for Sources within the Regional Haze Special Protection Area

18 AAC 50.265

Per 18 AAC 50.265, an application for a construction permit, new permit, permit renewal, or permit modification must include the following information:

18 AAC 50.265(4)(A) – Anticipated Equipment Major Maintenance Schedules

The anticipated equipment major maintenance schedules are currently unavailable.

18 AAC 50.265(4)(B) – Best Estimate of Projected Significant Emissions Unit Equipment Life, if known

The projected equipment life of each significant emissions unit located at the stationary source is currently unavailable.

18 AAC 50.265(4)(C) – Regional Haze Reasonable Further Progress Goals – Assessment of Stationary Source Impacts

The existing stationary source was included in the baseline analysis the Alaska Department of Environmental Conservation (ADEC) prepared for developing 18 AAC 50.265. According to the State Air Quality Control Plan Volume II, Section III.K.13.F, the Regional Haze Rule requires the ADEC to submit a plan to make reasonable progress towards natural visibility conditions at Class I areas. To achieve this goal, the ADEC is required to develop a long-term strategy that must “include emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress’’ and “identify all anthropogenic sources of visibility impairment considered by the state in developing its long-term strategy”. In developing these goals, the ADEC selected sources and considered four factors to evaluate the potential control measures for the selected sources: 1) cost of compliance; 2) time necessary for compliance; 3) energy and non-air quality environmental impacts; and 4) remaining useful life. To select sources for evaluation, the ADEC used a two-step approach. The initial step (step one) involved an area of influence (AOI) and weighted emissions potential (WEP) analysis. The final step (step two) involved a Q/d analysis (quantity of actual emissions in tons per year divided by distance in kilometers). The Grayling Platform was eliminated from consideration for inclusion in the four-factor analysis in step two of the selection process. In the State Air Quality Control Plan Volume II, Section III.K, Appendix III.K.13.F, ADEC states that “ADEC, upon consideration of the former limited analysis, concludes that Hilcorp is employing the most practical and effective control regime for their SO_2 emissions at the Grayling Platform stationary source.” (See pages III.K.13.F-24 through 28.) Additional information about this ADEC regional haze determination is available on the cited SIP pages.

As part of the PSD rules promulgated under 40 C.F.R. 52.21 and adopted by reference in 18 AAC 50.040 with the changes indicated in 18 AAC 50.306, an analysis of additional impacts on Class I areas must be submitted to reviewing authorities as part of a PSD permit application to demonstrate that significant deterioration of the air quality in nearby Class I areas will not occur as a result of the proposed project addressed by the application. The air quality-related values (AQRV) analysis performed and provided in **Attachment F** of this application (see **Section F5**) shows that the Grayling Platform Fuel Gas H_2S Increase Project (Project) will have negligible impacts on air quality in nearby Class I areas. Therefore, the Project’s impact on the State’s regional haze reasonable further progress goals for Class I areas is inconsequential.

18 AAC 50.265(4)(D) – Regional Haze Reasonable Further Progress Goals - Mitigation Measures to Minimize Adverse Impacts

Per the results of the processes described above under our response to meet the requirements of 18 AAC 50.265(4)(C), no mitigation measures have been identified as necessary to minimize any potential adverse impacts on the reasonable further progress goals for Class I areas, as identified in the State Air Quality Control Plan, adopted by reference in 18 AAC 50.030.

Attachment A-2

Criteria Pollutant Emissions Calculations (Electronically Enclosed)

Sulfur dioxide (SO_2) is the only direct emission increase associated with the Project. The Project's fuel gas H_2S content increase will not impact direct emissions of other criteria pollutants. However, the estimated potential emissions of all criteria pollutants resulting from operation of emissions units located at the Grayling Platform are included in the Excel emissions spreadsheet provided with this application.

Grayling Platform

Fuel Gas H_2S Increase Project
Construction Permit Application

Attachment B – Project Description, Emissions and Regulatory Review

Hilcorp Alaska, LLC

3800 Centerpoint Drive, Suite 1400, Anchorage, Alaska, 99503

Prepared by:

SLR International Corporation

2700 Gambell Street, Suite 200, Anchorage, Alaska, 99503

SLR Project No.: 105.00874.20026

October 2023

Making Sustainability Happen

Grayling Platform
Fuel Gas H_2S Increase Project
Construction Permit Application
Attachment B - Project Description, Emissions and Regulatory Review

Prepared for:

Hilcorp Alaska, LLC
3800 Centerpoint Drive, Suite 1400
Anchorage, AK 99503

This document has been prepared by SLR International Corporation (SLR). The material and data in this report were prepared under the supervision and direction of the undersigned.

Jeff Alger
Principal Engineer

Sims Duggins
Senior Principal

TA DAMIANA

Tom Damiana
Principal Engineer

Table of Contents

B1. Project Description **B1-1**

B2. Project Emissions **B2-1**

B3. Regulatory Applicability **B3-1**

- B3.1 Major Source (PSD) Permitting Under 18 AAC 50.306 .... B3-1
  - B3.1.1 Overview of PSD Process B3-1
  - B3.1.2 Major Modification B3-2
  - B3.1.3 Project PSD Permit Applicability Under 18 AAC 50.306 .... B3-2
- B3.2 Minor Source Permitting B3-3
  - B3.2.1 Minor Source Permitting Under 18 AAC 50.502(c)(3) - Air Quality Protection B3-3
  - B3.2.2 Project Minor Source Permit Applicability Under 18 AAC 50.302(c)(3) B3-3
  - B3.2.3 Minor Source Permitting Under 18 AAC 50.508(6) – Revising or Rescinding Terms and Conditions of a Title I Permit B3-3
- B3.3 NSPS Applicability B3-3
- B3.4 NESHAP Applicability B3-5

Tables

Table B2-1: Net Emissions Change from Grayling Platform Fuel Gas H_2S Increase Project B2-1

Table B3-1: NSPS Subpart KKKK Emission Standards B3-4

Appendices

Appendix A Supporting Documentation for Baseline Emissions

Appendix B Supporting Documentation for Projected Actual/ Potential Emissions

Appendix C Baseline Actual/ Projected Actual/ Potential Emissions Summary

B1. Project Description

Hilcorp Alaska, LLC (Hilcorp) owns and operates the Grayling Platform (Grayling) located in Upper Cook Inlet, Alaska. Grayling is an offshore oil and gas production platform, producing gas and oil with some residual water in the oil. The platform currently burns all its produced gas in platform combustion devices and imports sweet gas from the Steelhead Platform to make up any shortages in gas supply. The two gas streams are comingled prior to being introduced into the fuel gas system on the platform.

Hilcorp submitted an air quality permit application to the Alaska Department of Environmental Conservation (ADEC) in 2018, which included, in part, a request to increase the Grayling fuel gas H_2S air quality protection limit from 250 ppmv to 400 ppmv. In response to that application, ADEC issued to Hilcorp Air Quality Control Minor Permit no. AQ0069MSS04 on February 14, 2019 for the Grayling Platform stationary source with the fuel gas H_2S limit set at 400 ppmv. One purpose of this application is to request an increase in the existing 400 ppmv monthly average stationary-source wide fuel gas H_2S content limit found in permit no. AQ0069MSS04, Revision 1, which is set as an ambient air quality protection limit. (See Condition 9 of the permit, found in **Attachment G** to this application.) Ambient air quality modeling and the air quality-related values analysis provided in **Attachment F** of this application demonstrate that the existing limit can be increased while still protecting ambient air quality and that the impact of the requested limit increase on the State's regional haze reasonable further progress goals for Class I areas is inconsequential.

This application also includes an analysis of Best Available Control Technology (BACT) because the change in actual emissions (comparing projected actual emissions to baseline actual emissions) associated with the proposed increase in the fuel gas H_2S content limit triggers review under the Prevention of Significant Deterioration (PSD) air quality permitting program as detailed in **Attachment B** of this application. Details of the BACT analysis are provided in **Attachment C** of this application.

Specifically, and in summary, with this application Hilcorp requests an increase of the short-term (i.e., monthly average) permitted fuel gas H_2S limit to 1,250 ppmv to protect ambient air quality and proposes to establish a BACT limit of 98 tons per year (tpy) of sulfur dioxide (SO_2) emissions based on an annual average fuel gas H_2S concentration of 650 ppmv.

This action is hereinafter referred to as the "Grayling Platform Fuel Gas H_2S Increase Project" or "the Project."

No emissions units will be added or modified as part of the Project.

B2. Project Emissions

The only direct emission increase associated with the Project is sulfur dioxide (SO_2). The increase in H_2S in the fuel gas will not have an impact on the direct emissions of other criteria pollutants. SO_2 emissions are summarized in **Table B2-1** for Grayling.

Table B2-1: Net Emissions Change from Grayling Platform Fuel Gas H_2S Increase Project

	SO_2 (tpy)
Projected Actual Emissions	98.0
Baseline Actual Emissions	27.9
Net Emissions Change	70.1

Baseline actual emissions (BAE) are calculated using the fuel gas volumetric flow and H_2S measured during the 24-consecutive month period between May 2014 and April 2016. Supporting documentation is provided in **Appendix A** and summarized in **Appendix C** of this section of the application.

Projected actual emissions (PAE) are based on a comingled fuel gas flow of 4,900 thousand standard cubic feet per day (Mscfd) and an H_2S content of 650 ppmv derived as shown below. The comingled volumetric flow used for the PAE is composed of 2,800 Mscfd of imported gas with an H_2S content of 1.6 ppmv and 2,100 Mscfd of produced gas with an estimated H_2S content of 1,400 ppmv. The projected volume of imported gas is based on the average of reported volumes between 2011 and 2020 (2,203 Mscfd) plus one standard deviation (595 Mscfd). The produced gas volumetric flowrate is based on the design capacity of the booster compressor. Supporting documentation is provided in **Appendix B** and summarized in **Appendix C** of this section of the application.

$$H_2S_c = \frac{(Q_{imp} * H_2S_{imp}) + (Q_{prod} * H_2S_{prod})}{Q_{tot} * SF}$$

where:

H_2S_c is the comingled fuel gas H_2S content.

Q_{imp} is the imported fuel gas volumetric flowrate = 2,800 Mscfd.

H_2S_{imp} is the imported fuel gas H_2S content = 1.6 ppmv.

Q_{prod} is the produced gas volumetric flowrate = 2,100 Mscfd.

H_2S_{prod} is the produced gas H_2S content = 1,400 ppmv.

Q_{tot} is the total fuel gas consumed on the platform = 4,900 Mscfd.

SF is an assumed safety factor = 0.92.

$$H_2S_c = \frac{(2{,}800 * 1.6) + (2{,}100 * 1{,}400)}{4{,}900 * 0.92} = 650 \text{ ppmv}$$

The SO_2 PAE are calculated using the following formula:

$$SO_2 = \frac{Q_{tot} * H_2S_c * 64 * 365}{379.6 * 1000 * 2{,}000}$$

where:

SO_2 is sulfur dioxide emissions expressed in units of tons per year from all significant gas-fired emissions units on the platform.

64 is the molecular weight of SO_2.

365 is the number of days per year.

379.6 is the volume (standard cubic feet) of gas per mole of gas at 14.696 psia and 60°F.

1000 is the factor to convert from Mscf to MMscf.

2,000 is the factor to convert from lbs to tons.

$$SO_2 = \frac{4{,}900 * 650 * 64 * 365}{379.6 * 1000 * 2{,}000} = 98 \text{ tons/year}$$

B3. Regulatory Applicability

B3.1 Major Source (PSD) Permitting Under 18 AAC 50.306

B3.1.1 Overview of PSD Process

With some exceptions, Federal provisions of 40 C.F.R. 51.166 (PSD) and 40 C.F.R. Part 52 (Approval and Promulgation of Implementation Plans), revised as of November 24, 2020, are adopted by reference in 18 AAC 50.040 (amended through September 7, 2022). Notably, EPA's final Project Emissions Accounting rule was promulgated November 24, 2020 (85 FR 74890).

As set out in the federal PSD regulations, incorporated by reference in 18 AAC 50, and described by EPA:[1]

An existing major stationary source proposing to undertake a physical change or a change in the method of operation (i.e., a "project") under the Prevention of Significant Deterioration (PSD) permitting program must determine whether that project will constitute a "major modification" subject to PSD preconstruction permitting requirements by following a two-step applicability test. Step 1 is to determine if the proposed project would result in a "significant emissions increase" of a regulated NSR pollutant. If the proposed project is determined to result in a significant emissions increase, Step 2 is followed to determine if the project would also result in a "significant net emissions increase" of that pollutant from the source. In other words, Step 1 considers the effect of the project alone and Step 2 considers the effect of the project and any other emission changes at the major stationary source that are contemporaneous to the project (i.e., generally within a 5-year period) and creditable.

An emissions increase of a regulated New Source Review (NSR) pollutant is considered "significant" if the emissions increase in Step 1 or 2, would be equal to or greater than any of the pollutant-specific Significant Emissions Rates (SERs) listed under the definition of "significant" in 40 C.F.R. 51.166(b)(23). The SER for SO_2 is 40 tpy. SO_2 is a precursor to particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) and, as a result, when PSD applicability is triggered for SO_2, it also is indirectly triggered for $PM_{2.5}$.

For existing units, the PSD regulation requires that the difference in pre- and post-project emissions be calculated based on the difference between a unit's BAE and its PAE after the project. BAE for existing units are determined based on the average rate of actual emissions (tpy) within the 10-year period immediately preceding the project. PAE for existing units are determined based on the maximum rate of actual emissions (tpy) a unit is projected to emit in the future.

Once a source determines that a significant emissions increase would occur in Step 1, then the source may deem the project to be a major modification or perform the Step 2 contemporaneous netting analysis to determine if there would be a significant net emissions increase at the major source and thus be subject to PSD permitting. A net emissions increase means, with respect to any regulated NSR pollutant emitted at a major stationary source, the amount by which the sum of the following exceeds zero: (a) [t]he increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to [40 C.F.R. 52.21](a)(2)(iv); and (b) [a]ny other increases and decreases

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[1] 85 FR 74890, November 24, 2020

in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable. The Step 2 contemporaneous netting analysis is conducted by adding the emissions increase from the project as determined in Step 1 to all other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the project and otherwise creditable.

Emissions increases and decreases are contemporaneous if they occur between "[t]he date 5 years before construction of the particular change commences; and [t]he date that the increase from a particular change occurs." An increase or decrease in actual emissions in Step 2 is creditable only if the EPA Administrator or other reviewing authority has not relied on it in issuing a PSD or nonattainment area new source review (NNSR) permit for the source and the permit is still in effect at the time the major modification occurs. Furthermore, emission increases in Step 2 are only creditable if the new level of actual emissions exceeds the old level of actual emissions. Emissions decreases in Step 2, on the other hand, are creditable only to the extent that the old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions and the decrease in actual emissions is enforceable as a practical matter at and after the time that actual construction of the particular change begins.

A project that results in a significant emissions increase in Step 1 and a significant net emissions increase in Step 2 of the two-step applicability test is a major modification that requires a preconstruction PSD permit.

B3.1.2 Major Modification

The definition of "major modification" in §52.21(b)(2) is not adopted in 18 AAC 50.040(h), but rather the term has the meaning given in in AS 46.14.990 and 18 AAC 50.990. For the purposes of 18 AAC 50.306, "major modification" is defined at 40 C.F.R. 51.166(b)(2). As provided in 40 C.F.R. 51.166(b)(2)(iii)(e), a physical change or change in the method of operation shall not include:

Use of an alternative fuel or raw material by a stationary source which:

(1) The source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975 pursuant to 40 C.F.R. 52.21 or under regulations approved pursuant to 40 C.F.R. subpart I or §51.166; or

(2) The source is approved to use under any permit issued under 40 C.F.R. 52.21 or under regulations approved pursuant to 40 C.F.R. 51.166.

The source (i.e., the Grayling Platform) is not approved to use the proposed "alternative fuel," as the fuel sulfur content of such fuel gas exceeds current limits set out in a Title I permit. Consequently, the change in fuel would be considered a physical change or change in the method of operation under 18 AAC 50.306 and the referenced federal standards.

B3.1.3 Project PSD Permit Applicability Under 18 AAC 50.306

Based on the Project's net emissions increase determined from the BAE to PAE test shown in **Table B2-1,** the proposed increase in fuel sulfur content will result in an increase in SO_2 emissions exceeding the 40 tpy SO_2 and $PM_{2.5}$ precursor significance thresholds. Therefore, the Project will be a major modification to an existing major stationary source. PSD review is required.

B3.2 Minor Source Permitting

B3.2.1 Minor Source Permitting Under 18 AAC 50.502(c)(3) - Air Quality Protection

Under Alaska’s Minor Permits regulation for air quality protection, 18 AAC 50.502(c)(3), an owner or operator must obtain a minor permit under the regulation before beginning a physical change to or a change in the method of operation of an existing stationary source with a potential to emit greater than 40 tpy SO_2 that will cause for SO_2 an emissions increase calculated at the discretion of the owner or operator as either an increase in potential to emit that is greater than 10 tpy SO_2 or an actual emissions and a net emissions increase greater than 10 tpy SO_2.

The terms “physical change to” or “a change in the method of operation” are not defined in 18 AAC 50, but the Department views a change in fuel sulfur as a physical change or change in the method of operation if the change would be prohibited under any enforceable permit condition. Condition 9 of Grayling Minor Permit AQ0069MSS04, Revision 1, establishes a stationary source-wide fuel gas H_2S content limit:

> “The Permittee shall not burn fuel gas with a hydrogen sulfide (H_2S) content greater than 400 parts per million volume (ppmv), monthly average, stationary source wide.”

Therefore, the Project will result in a change that requires an assessment of the increase in SO_2 emissions to determine if minor source permitting under 18 AAC 50.502(c)(3) is triggered.

B3.2.2 Project Minor Source Permit Applicability Under 18 AAC 50.302(c)(3)

The requested increase in fuel gas H_2S content from 400 ppmv to 650 ppmv (stationary source-wide) exceeds the current permit limit and results in an increase in potential to emit (PTE) SO_2 exceeding the 10 tpy threshold in 18 AAC 50.502(c)(3). However, SO_2 minor source permitting under 18 AAC 50.502(c)(3) is not addressed by this application since PSD permitting for SO_2 under 18 AAC 50.306 has been triggered, which supersedes the minor source permitting requirement.

B3.2.3 Minor Source Permitting Under 18 AAC 50.508(6) – Revising or Rescinding Terms and Conditions of a Title I Permit

Hilcorp requests a permit under 18 AAC 50.508(6) to revise terms or conditions previously established in a Title I Permit (Minor Permit AQ0069MSS04) issued under 18 AAC 50.502. The details of that portion of this application are provided in **Attachment D** of this application.

B3.3 NSPS Applicability

Federal New Source Performance Standard (NSPS), 40 C.F.R. Part 60, Subpart KKKK—Standards of Performance for Stationary Combustion Turbines is the only NSPS rule that may potentially become applicable to Grayling because of the Project. Subpart KKKK regulates stationary combustion turbine affected facilities as defined in 40 C.F.R. §§60.4305 and 60.4420. The rule applies to each affected turbine for which “construction,” “modification,” or “reconstruction,” (defined in 40 C.F.R. §§60.2, 60.14 and 60.15) commenced after February 18, 2005. Affected “modified” or “reconstructed” turbines located in the non-continental areas, including offshore platforms, are subject to standards for NO_X and SO_2 or fuel sulfur limits as summarized in **Table B3-1**.

Table B3-1: NSPS Subpart KKKK Emission Standards

Combustion Turbine Type	Combustion Turbine Heat Input at Peak Load (HHV)	NOx Emission Standard [§60.4320 and Table 1 to Subpart KKKK]	SO_2 Emission Standard [§60.4330(b)]
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/hr and ≤850 MMBtu/hr	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).	SO_2: 780 ng/J (6.2 lb/MWh) gross output; or Fuel containing total potential sulfur: 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input
Modified or reconstructed turbine	≤ 50 MMBtu/hr	150 ppm at 15 percent O_2 or 1,100 ng/J of useful output (8.7 lb/MWh)	
Turbines operating at <75% of peak load	≤ 30 MW output		
Modified and reconstructed offshore turbines			
Turbine operating at temperatures less than 0 °F			

Certain stationary combustion turbines in operation at Grayling for which “construction,” “reconstruction” or “modification” commenced after October 3, 1977 and prior to February 18, 2005 are “affected facilities” for purposes of NSPS Subpart GG—Standards of Performance for Stationary Gas Turbines. The operating permit (AQ0069TVP03) includes terms and conditions pertaining to NSPS Subpart GG. NSPS Subparts GG and KKKK, revised as of April 2, 2020, are adopted by reference as they apply to a Title V source as provided by 18 AAC 50.040(a)(2)(V) and (QQ), respectively.

All the stationary combustion turbines at Grayling are “existing facilities” for purposes of NSPS Subpart KKKK because construction, reconstruction or modification commenced on or before February 18, 2005. As provided by §60.14(a), upon “modification,” an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

For purposes of NSPS Subpart KKKK, a modification to an existing turbine occurs as a result of any physical or operational change to the turbine that results in an increase in the emission rate to the atmosphere of NO_X and/or SO_2. The term “physical or operational change” is not defined in NSPS or any other federal Clean Air Act program, but some activities are not modifications, as provided in §60.14(e), including:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of [§60.14] and §60.15.

(2) An increase in production rate of an existing facility if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under [Part 60] becomes applicable to that source type, as provided by §60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

An increase in the sulfur content of the fuel gas burned in the gas-fired stationary combustion turbines is not a “modification” for purposes of NSPS as provided in 40 C.F.R. §60.14(e)(4) because the turbines are designed to accommodate the fuel gas. No physical change to any combustion turbine is necessary to accommodate the “alternative” fuel gas. Switching fuels is clearly excluded from a modification as provided by §60.14(e)(4). Stationary turbines that are currently existing facilities for purposes of Subpart KKKK will remain as such. Subpart KKKK will not apply.

B3.4 NESHAP Applicability

The Grayling Platform source has the potential to emit less than 10 tpy of any individual HAP and less than 25 tpy of total HAP, and the facility is an “area source.” There are two National Emission Standards for Hazardous Air Pollutants for Source Categories (NESHAP), 40 C.F.R. Part 63, rules that are relevant to the area source facility:

> Subpart HH—National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities; and
>
> Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

An increase in fuel sulfur content will not change the classification of the Grayling Platform as an area source of HAP, nor will the Project result in any change in applicability or non-applicability of the standards and requirements to any emissions units at Grayling under the relevant NESHAP.

Appendix A Supporting Documentation for Baseline Emissions

Grayling Platform

Fuel Gas H_2S Increase Project
Construction Permit Application
Attachment B – Project Description, Emissions and Regulatory Review

Hilcorp Alaska, LLC

SLR Project No.: 105.00874.20026

October 2023

Grayling
Gas Disposition

2014	**Grayling Platform**												
(vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	6,030	8,871	8,249	9,832	6,668	8,368	4,829	2,422	308	261	4,175	5,361	**65,374**
Flared/Vented +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,720	3,360	3,720	3,600	3,720	3,600	3,690	3,720	3,540	3,720	3,600	3,720	**43,710**
Lease Ops	151,474	140,560	150,499	135,959	152,550	141,669	154,655	146,960	89,018	87,429	123,639	93,035	**1,567,447**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	161,224	152,791	162,468	149,391	162,938	153,637	163,174	153,102	92,866	91,410	131,414	102,116	**1,676,531**
Total (check)	--	--	--	--	--	--	--	--	--	--	--	--	
Total Vented or Flared (Check)	--	--	--	--	--	--	--	--	--	--	--	--	
Production Gas Consumed (lease ops + purchased + transferred from)	151,474	140,560	150,499	135,959	152,550	141,669	154,655	146,960	89,018	87,429	123,639	93,035	**1,567,447**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred From	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred To (TBPF, Dolly, King, TBU A-15)	35,177	35,298	40,049	34,522	30,451	48,965	40,988	42,060	47,122	57,326	74,851	60,589	**547,398**
COVs to TBPF	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Grayling
Gas Disposition

2015	**Grayling Platform**												
(vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	7,085	6,427	8,878	4,709	5,824	9,683	7,578	7,506	5,457	1,901	702	719	**66,469**
Flared/Vented +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,720	3,360	3,720	3,600	3,600	3,600	3,720	3,720	3,600	3,720	3,600	3,720	**43,680**
Lease Ops	87,475	83,217	92,666	159,980	195,492	186,231	200,892	221,725	204,940	202,616	171,907	167,441	**1,974,582**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	98,280	93,004	105,264	168,289	204,916	199,514	212,190	232,951	213,997	208,237	176,209	171,880	**2,084,731**
Total (check)	--	--	--	--	--	--	--	--	--	--	--	--	
Production Gas Consumed (lease ops + purchased + transferred from)	87,475	83,217	92,666	159,980	195,492	186,231	200,892	221,725	204,940	202,616	171,907	167,441	**1,974,582**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred From	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred To (TBPF, Dolly, King, TBU A-15)	65,852	59,070	69,168	73,543	82,030	75,451	84,448	97,066	98,626	96,090	81,805	90,592	**973,741**
COVs to TBPF	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Grayling
Gas Disposition

2016	**Grayling Platform**												
(vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	145	3,967	979	5,498	6,336	2,140	2,704	1,767	2,195	2,265	2,106	1,908	**32,010**
Flared/Vented +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,600	3,480	3,720	3,600	3,720	3,600	3,600	3,720	3,564	3,600	3,600	3,720	**43,524**
Lease Ops	169,647	159,768	183,006	153,701	197,580	109,081	117,234	127,961	122,670	127,496	127,876	113,936	**1,709,956**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	173,392	167,215	187,705	162,799	207,636	114,821	123,538	133,448	128,429	133,361	133,582	119,564	**1,785,490**
Total (check)	--	--	--	--	--	--	--	--	--	--	--	--	
Production Gas Consumed (lease ops + purchased + transferred from)	169,647	159,768	183,006	153,701	197,580	109,081	117,234	127,961	122,670	127,496	127,876	113,936	**1,709,956**
NGL Gas Equivalent	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred from (Steelhead)	94,984	93,320	84,791	79,929	81,079	70,681	73,389	81,902	76,635	82,171	82,794	72,354	**974,029**
Transferred To (TBPF, Dolly, King, TBU A-15)	0	0	0	0	0	0	0	0	0	0	0	0	**0**

C:\Jalger\Hilcorp\Grayling_Steelhead PSD\Fuel Gas Usage\Gsdisp16.xlsx

H2S Report

Start: 01/01/2014 **End:** 12/31/2016

GRAYLING PLATFORM - OIL

Location	Test Date	Test Time	Quality	Limit	Method
GR TOTAL FUEL GAS	01/03/2014	01:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/10/2014	01:30:00	95.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/17/2014	01:15:00	125.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/24/2014	01:10:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/31/2014	01:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	02/14/2014	01:10:00	120.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	02/28/2014	01:00:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	03/07/2014	01:30:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	03/14/2014	02:40:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	03/21/2014	01:45:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	03/28/2014	01:00:00	170.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/04/2014	01:20:00	140.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/11/2014	01:55:00	110.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/18/2014	01:15:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/25/2014	01:00:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/02/2014	01:20:00	190.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/09/2014	01:10:00	105.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/16/2014	01:30:00	190.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/23/2014	01:00:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/30/2014	01:20:00	170.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/06/2014	01:15:00	250.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/13/2014	01:25:00	205.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/20/2014	01:00:00	195.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/27/2014	01:20:00	215.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/04/2014	02:40:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/11/2014	01:20:00	140.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/18/2014	13:20:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/25/2014	01:30:00	170.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/01/2014	02:08:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/08/2014	02:55:00	3.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/15/2014	01:00:00	190.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/22/2014	01:10:00	110.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/29/2014	02:15:00	210.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/05/2014	02:10:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/12/2014	01:00:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/19/2014	01:30:00	170.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/26/2014	01:10:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/03/2014	02:00:00	120.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/10/2014	01:00:00	280.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/17/2014	01:30:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/24/2014	01:10:00	210.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/31/2014	01:10:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/07/2014	01:00:00	225.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/14/2014	01:30:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/21/2014	01:10:00	120.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/28/2014	01:15:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/05/2014	01:00:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/12/2014	01:20:00	210.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/19/2014	01:10:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/26/2014	01:10:00	210.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/02/2015	01:00:00	190.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/09/2015	02:10:00	220.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/16/2015	01:55:00	240.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/23/2015	01:10:00	240.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/30/2015	01:00:00	240.0000	400	GPA 2377-86

H2S Report

Start: 01/01/2014 **End:** 12/31/2016

GRAYLING PLATFORM - OIL

Location	Test Date	Test Time	Quality	Limit	Method
GR TOTAL FUEL GAS	02/06/2015	20:55:00	240.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	02/13/2015	14:30:00	240.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	02/20/2015	16:00:00	220.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	02/27/2015	12:00:00	230.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	03/06/2015	21:00:00	240.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	03/13/2015	18:00:00	230.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	03/20/2015	21:30:00	245.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	03/27/2015	12:00:00	240.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/03/2015	21:30:00	220.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/10/2015	20:00:00	120.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/17/2015	10:00:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/24/2015	17:00:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/08/2015	14:10:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/15/2015	15:00:00	220.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/22/2015	04:30:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/29/2015	13:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/05/2015	13:30:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/12/2015	20:30:00	120.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/19/2015	12:00:00	220.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/26/2015	19:00:00	210.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/03/2015	16:00:00	210.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/10/2015	15:20:00	125.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/17/2015	12:00:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/31/2015	13:00:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/07/2015	07:30:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/14/2015	17:00:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/21/2015	20:30:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/28/2015	12:50:00	150.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/04/2015	07:30:00	150.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/11/2015	20:00:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/18/2015	14:00:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/25/2015	19:00:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/02/2015	13:15:00	120.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/09/2015	18:00:00	150.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/16/2015	21:30:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/23/2015	15:20:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/30/2015	21:30:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/06/2015	12:00:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/13/2015	15:30:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/20/2015	14:30:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/27/2015	13:00:00	150.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/04/2015	18:00:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/11/2015	14:00:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/18/2015	13:30:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/25/2015	21:00:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/01/2016	12:00:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/08/2016	17:00:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/15/2016	15:00:00	140.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/22/2016	04:00:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	01/30/2016	19:00:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	02/05/2016	21:00:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	02/12/2016	03:30:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	02/19/2016	09:30:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	02/26/2016	20:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	03/04/2016	19:00:00	100.0000	400	GPA 2377-86

H2S Report

Start: 01/01/2014 **End:** 12/31/2016

GRAYLING PLATFORM - OIL

Location	Test Date	Test Time	Quality	Limit	Method
GR VAPOR RECOVERY	03/04/2016	19:30:00	800.0000		GPA 2377-86
GR TOTAL FUEL GAS	03/11/2016	03:30:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	03/18/2016	21:00:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	03/25/2016	21:00:00	120.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/01/2016	00:00:00	140.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/08/2016	03:15:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/15/2016	19:30:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/22/2016	20:15:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	04/29/2016	21:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/06/2016	03:30:00	120.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/13/2016	12:00:00	125.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/14/2016	12:00:00	125.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/20/2016	13:00:00	110.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	05/27/2016	07:30:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/03/2016	00:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/10/2016	22:00:00	180.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/17/2016	03:35:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	06/24/2016	12:00:00	190.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/01/2016	03:30:00	140.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/08/2016	22:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/15/2016	18:10:00	175.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/22/2016	21:00:00	125.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	07/29/2016	03:00:00	120.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/05/2016	21:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/12/2016	00:20:00	175.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/19/2016	16:00:00	150.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	08/25/2016	00:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/02/2016	22:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/09/2016	22:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/16/2016	18:00:00	140.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/23/2016	22:00:00	220.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	09/30/2016	20:00:00	120.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/09/2016	00:00:00	150.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/14/2016	15:00:00	100.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/21/2016	23:30:00	50.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	10/28/2016	14:30:00	170.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/04/2016	00:00:00	110.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/11/2016	12:00:00	150.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/18/2016	23:00:00	220.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	11/25/2016	14:30:00	170.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/02/2016	19:10:00	200.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/09/2016	14:00:00	150.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/16/2016	23:00:00	190.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/23/2016	14:00:00	160.0000	400	GPA 2377-86
GR TOTAL FUEL GAS	12/30/2016	20:55:00	175.0000	400	GPA 2377-86

Appendix B Supporting Documentation for Projected Actual/ Potential Emissions

Grayling Platform

Fuel Gas H_2S Increase Project
Construction Permit Application
Attachment B – Project Description, Emissions and Regulatory Review

Hilcorp Alaska, LLC

SLR Project No.: 105.00874.20026

October 2023

Grayling
Gas Disposition

2011 (vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	Total
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared -1 hour	7,390	5,408	6,662	8,189	8,853	6,557	5,937	9,362	9,133	11,963	8,054	5,927	**93,435**
Flared +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,720	3,360	3,720	3,600	3,720	3,600	3,720	3,720	3,600	3,720	3,600	3,720	**43,800**
Lease Ops	154,336	132,021	148,663	133,537	130,589	120,357	132,804	132,636	131,682	121,994	122,951	129,543	**1,591,113**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	165,446	140,789	159,045	145,326	143,162	130,514	142,461	145,718	144,415	137,677	134,605	139,190	**1,728,348**
check	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	ok	
Total (formula)	165,446	140,789	159,045	145,326	143,162	130,514	142,461	145,718	144,415	137,677	134,605	139,190	**1,728,348**
Total Vented of Flared	11,110	8,768	10,382	11,789	12,573	10,157	9,657	13,082	12,733	15,683	11,654	9,647	**137,235**
Real Flare Total (inc. purchase, not vented) Assessables link!	11,110	8,768	10,382	11,789	12,573	10,157	9,657	13,082	12,733	15,683	11,654	9,647	**137,235**
Real Consumption (lease ops + purchased + transferred from - dearator-purchased flare)	154,336	132,021	148,663	133,537	130,589	120,357	132,804	132,636	131,682	121,994	122,951	129,543	**1,591,113**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred From	63,537	55,214	66,993	42,084	41,569	40,445	54,019	63,262	67,103	65,915	67,596	66,216	**693,953**
Transferred To (TBPF, Dolly, King, TBU A-15)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
COVs to TBPF	0	0	0	0	0	0	0	0	0	0	0	0	**0**

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Grayling
Gas Disposition

2012 (vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	5,028	2,757	1,717	1,630	2,548	2,823	2,785	3,472	3,805	3,824	4,382	4,585	**39,356**
Flared/Vented +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,740	3,499	1,718	3,620	3,740	3,600	3,720	3,720	3,600	3,720	3,600	3,720	**41,997**
Lease Ops	133,353	113,743	127,482	125,077	133,143	122,261	129,888	0	0	139,227	169,068	133,525	**1,326,767**
Other	0	0	0	0	0	0	0	132,155	128,884	0	0	0	**261,039**
Total	142,121	119,999	130,917	130,327	139,431	128,684	136,393	139,347	136,289	146,771	177,050	141,830	**1,669,159**
Total (check)	--	--	--	--	--	--	--	--	--	--	--	--	
Production Gas Consumed (lease ops + purchased + transferred from)	200,685	174,686	193,470	196,837	216,782	214,768	236,290	91,401	90,492	238,865	272,347	211,414	**2,338,037**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred From	67,332	60,943	65,988	71,760	83,639	92,507	106,402	91,401	90,492	99,638	103,279	77,889	**1,011,270**
Transferred To (TBPF, Dolly, King, TBU A-15)	0	0	0	0	0	0	0	0	0	0	0	0	**0**
COVs to TBPF	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Grayling
Gas Disposition

2013	Grayling Platform												
(vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	2,954	2,544	10,913	4,282	17,320	18,002	16,252	25,265	19,817	12,013	13,398	7,202	**149,962**
Flared/Vented +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,720	3,360	3,720	3,600	3,720	3,600	3,720	3,720	3,600	3,720	3,600	3,720	**43,800**
Lease Ops	97,926	86,313	74,476	80,770	53,863	144,858	143,407	134,950	132,576	137,976	139,832	152,113	**1,379,060**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	104,600	92,217	89,109	88,652	74,903	166,460	163,379	163,935	155,993	153,709	156,830	163,035	**1,572,822**
Total (check)	--	--	--	--	--	--	--	--	--	--	--	--	
Total Vented or Flared (Check)	--	--	--	--	--	--	--	--	--	--	--	--	
Production Gas Consumed (lease ops + purchased + transferred from)	143,386	127,346	142,773	129,833	98,505	182,283	175,368	170,760	161,477	168,667	139,832	152,113	**1,792,343**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred From	45,460	41,033	68,297	49,063	44,642	37,425	31,961	35,810	28,901	30,691	0	0	**413,283**
Transferred To (TBPF, Dolly, King, TBU A-15)	0	0	0	0	0	0	0	0	0	0	29,364	33,748	**63,112**
COVs to TBPF	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Grayling
Gas Disposition

2014	**Grayling Platform**												
(vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	6,030	8,871	8,249	9,832	6,668	8,368	4,829	2,422	308	261	4,175	5,361	**65,374**
Flared/Vented +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,720	3,360	3,720	3,600	3,720	3,600	3,690	3,720	3,540	3,720	3,600	3,720	**43,710**
Lease Ops	151,474	140,560	150,499	135,959	152,550	141,669	154,655	146,960	89,018	87,429	123,639	93,035	**1,567,447**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	161,224	152,791	162,468	149,391	162,938	153,637	163,174	153,102	92,866	91,410	131,414	102,116	**1,676,531**
Total (check)	--	--	--	--	--	--	--	--	--	--	--	--	
Total Vented or Flared (Check)	--	--	--	--	--	--	--	--	--	--	--	--	
Production Gas Consumed (lease ops + purchased + transferred from)	151,474	140,560	150,499	135,959	152,550	141,669	154,655	146,960	89,018	87,429	123,639	93,035	**1,567,447**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred From	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred To (TBPF, Dolly, King, TBU A-15)	35,177	35,298	40,049	34,522	30,451	48,965	40,988	42,060	47,122	57,326	74,851	60,589	**547,398**
COVs to TBPF	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Grayling
Gas Disposition

2015	**Grayling Platform**												
(vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	7,085	6,427	8,878	4,709	5,824	9,683	7,578	7,506	5,457	1,901	702	719	**66,469**
Flared/Vented +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,720	3,360	3,720	3,600	3,600	3,600	3,720	3,720	3,600	3,720	3,600	3,720	**43,680**
Lease Ops	87,475	83,217	92,666	159,980	195,492	186,231	200,892	221,725	204,940	202,616	171,907	167,441	**1,974,582**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	98,280	93,004	105,264	168,289	204,916	199,514	212,190	232,951	213,997	208,237	176,209	171,880	**2,084,731**
Total (check)	--	--	--	--	--	--	--	--	--	--	--	--	
Production Gas Consumed (lease ops + purchased + transferred from)	87,475	83,217	92,666	159,980	195,492	186,231	200,892	221,725	204,940	202,616	171,907	167,441	**1,974,582**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred From	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred To (TBPF, Dolly, King, TBU A-15)	65,852	59,070	69,168	73,543	82,030	75,451	84,448	97,066	98,626	96,090	81,805	90,592	**973,741**
COVs to TBPF	0	0	0	0	0	0	0	0	0	0	0	0	**0**

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Grayling
Gas Disposition

2016	**Grayling Platform**												
(vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	145	3,967	979	5,498	6,336	2,140	2,704	1,767	2,195	2,265	2,106	1,908	**32,010**
Flared/Vented +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,600	3,480	3,720	3,600	3,720	3,600	3,600	3,720	3,564	3,600	3,600	3,720	**43,524**
Lease Ops	169,647	159,768	183,006	153,701	197,580	109,081	117,234	127,961	122,670	127,496	127,876	113,936	**1,709,956**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	173,392	167,215	187,705	162,799	207,636	114,821	123,538	133,448	128,429	133,361	133,582	119,564	**1,785,490**
Total (check)	--	--	--	--	--	--	--	--	--	--	--	--	
Production Gas Consumed (lease ops + purchased + transferred from)	169,647	159,768	183,006	153,701	197,580	109,081	117,234	127,961	122,670	127,496	127,876	113,936	**1,709,956**
NGL Gas Equivalent	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred from (Steelhead)	94,984	93,320	84,791	79,929	81,079	70,681	73,389	81,902	76,635	82,171	82,794	72,354	**974,029**
Transferred To (TBPF, Dolly, King, TBU A-15)	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Grayling
Gas Disposition

2017	**Grayling Platform**												
(vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	992	160	2,061	1,281	1,066	409	1,900	607	1,905	54	343	152	**10,930**
Flared/Vented +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,720	3,360	3,720	3,600	3,720	3,600	3,720	3,720	3,600	3,722	3,600	3,720	**43,802**
Lease Ops	86,796	98,585	100,988	103,182	78,483	71,194	68,737	68,173	93,802	105,719	105,199	108,530	**1,089,388**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	91,508	102,105	106,769	108,063	83,269	75,203	74,357	72,500	99,307	109,495	109,142	112,402	**1,144,120**
Total (check)	--	--	--	--	--	--	--	--	--	--	--	--	
Total Vented or Flared (Check)	--	--	--	--	--	--	--	--	--	--	--	--	
Production Gas Consumed (lease ops + purchased + transferred from)	86,796	98,585	100,988	103,182	78,483	71,194	68,737	68,173	93,802	105,719	105,199	108,530	**1,089,388**
NGL Gas Equivalent	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred from (Steelhead)	53,381	68,154	76,761	74,295	52,672	46,816	49,168	46,934	74,951	75,300	75,976	84,552	**778,960**
Transferred To (TBPF, Dolly, King, TBU A-15)	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Grayling
Gas Disposition

2018	**Grayling Platform**												
(vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	358	343	372	399	465	285	486	480	277	18	859	2,391	**6,733**
Flared/Vented +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,720	3,360	3,720	3,600	3,720	3,600	3,720	3,720	3,600	3,600	3,600	3,720	**43,680**
Lease Ops	109,533	86,297	91,945	93,240	103,251	84,457	90,315	118,715	107,840	118,112	111,847	114,324	**1,229,876**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	113,611	90,000	96,037	97,239	107,436	88,342	94,521	122,915	111,717	121,730	116,306	120,435	**1,280,289**
Total (check)	--	--	--	--	--	--	--	--	--	--	--	--	
Production Gas Consumed (lease ops + purchased + transferred from)	109,533	86,297	91,945	93,240	103,251	84,457	90,315	118,715	107,840	118,112	111,847	114,324	**1,229,876**
NGL Gas Equivalent	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred from (Steelhead)	78,942	62,240	71,328	68,182	73,737	54,751	60,512	80,160	72,698	89,980	72,711	80,065	**865,306**
Transferred To (TBPF, Dolly, King, TBU A-15)	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Grayling
Gas Disposition

2019	**Grayling Platform**												
(vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	1,482	1,658	2,762	2,812	2,691	1,695	1,882	1,985	1,887	3,485	2,081	1,616	**26,036**
Flared/Vented +1 hour	0	0	0	0	589	0	0	0	0	0	0	0	**589**
Pilot & Purge	3,720	3,360	3,720	3,600	3,720	3,600	3,720	3,720	3,480	3,720	3,600	3,720	**43,680**
Lease Ops	118,001	111,458	98,392	112,253	108,104	105,348	119,621	114,452	106,924	106,257	113,919	116,451	**1,331,180**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	123,203	116,476	104,874	118,665	115,104	110,348	125,223	120,157	112,291	113,462	119,600	121,787	**1,401,190**
Production Gas Consumed (lease ops + purchased + transferred from)	118,001	111,458	98,392	112,253	108,104	105,348	119,621	114,452	106,924	106,257	113,919	116,451	**1,331,180**
NGL Gas Equivalent	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred from (Steelhead)	83,781	78,143	66,709	77,375	79,316	72,801	86,603	81,116	77,234	72,448	76,569	80,026	**932,121**
Transferred To (TBPF, Dolly, King, TBU A-15)	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Grayling
Gas Disposition

2020	**Grayling Platform**												
(vol. in mcf)	January	February	March	April	May	June	July	August	September	October	November	December	**Total**
Sold	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Reinjected	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Flared/Vented -1 hour	2,330	2,190	1,878	1,633	1,276	837	813	774	1,018	757	783	763	**15,052**
Flared/Vented +1 hour	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Pilot & Purge	3,720	3,480	3,720	3,600	3,720	1,980	1,860	1,860	1,800	1,860	1,800	1,860	**31,260**
Lease Ops	114,338	105,124	93,895	77,649	59,352	67,304	68,636	65,536	96,613	98,027	96,559	97,107	**1,040,140**
Other	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Total	120,388	110,794	99,493	82,882	64,348	70,121	71,309	68,170	99,431	100,644	99,142	99,730	**1,086,452**
Total (check)	--	--	--	--	--	--	--	--	--	--	--	--	
Total Vented or Flared (Check)	--	--	--	--	--	--	--	--	--	--	--	--	
Production Gas Consumed (lease ops + purchased + transferred from)	114,338	105,124	93,895	77,649	59,352	67,304	68,636	65,536	96,613	98,027	96,559	97,107	**1,040,140**
NGL Gas Equivalent	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Purchased Gas	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Transferred from (Steelhead)	80,119	73,341	66,593	50,547	42,130	44,230	45,329	42,765	69,244	70,097	71,091	66,947	**722,433**
Transferred To (TBPF, Dolly, King, TBU A-15)	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Hilcorp Alaska, LLC
Grayling Platform
Projected Gas Distribution

Year	Month	Produced Gas (Mscf)	Imported Gas (Mscf)	Produced Gas (Mscfd)	Imported Gas (Mscfd)
2011	January	101,909	63,537	3,287	2,050
	February	85,575	55,214	3,056	1,972
	March	92,052	66,993	2,969	2,161
	April	103,242	42,084	3,441	1,403
	May	101,593	41,569	3,277	1,341
	June	90,069	40,445	3,002	1,348
	July	88,442	54,019	2,853	1,743
	August	82,456	63,262	2,660	2,041
	September	77,312	67,103	2,577	2,237
	October	71,762	65,915	2,315	2,126
	November	67,009	67,596	2,234	2,253
	December	72,974	66,216	2,354	2,136
2012	January	74,790	67,332	2,413	2,172
	February	59,056	60,943	2,036	2,101
	March	64,929	65,988	2,094	2,129
	April	58,567	71,760	1,952	2,392
	May	55,792	83,639	1,800	2,698
	June	36,177	92,507	1,206	3,084
	July	29,991	106,402	967	3,432
	August	47,948	91,401	1,547	2,948
	September	45,797	90,492	1,527	3,016
	October	47,133	99,638	1,520	3,214
	November	73,771	103,279	2,459	3,443
	December	63,941	77,889	2,063	2,513
2013	January	59,140	45,460	1,908	1,466
	February	51,184	41,033	1,828	1,465
	March	20,812	68,297	671	2,203
	April	39,589	49,063	1,320	1,635
	May	30,261	44,642	976	1,440
	June	129,035	37,425	4,301	1,248
	July	131,418	31,961	4,239	1,031
	August	128,125	35,810	4,133	1,155
	September	127,092	28,901	4,236	963
	October	123,018	30,691	3,968	990
	November				
	December				

Hilcorp Alaska, LLC
Grayling Platform
Projected Gas Distribution

Year	Month	Produced Gas (Mscf)	Imported Gas (Mscf)	Produced Gas (Mscfd)	Imported Gas (Mscfd)
2014	January	126,047	35,177	4,066	1,135
	February	117,493	35,298	4,196	1,261
	March	122,420	40,049	3,949	1,292
	April	114,871	34,522	3,829	1,151
	May	132,488	30,451	4,274	982
	June	104,672	48,965	3,489	1,632
	July	122,187	40,988	3,942	1,322
	August	111,043	42,060	3,582	1,357
	September	48,563	47,122	1,619	1,571
	October	34,086	57,326	1,100	1,849
	November	56,563	74,851	1,885	2,495
	December	41,529	60,589	1,340	1,954
2015	January	32,429	65,852	1,046	2,124
	February	33,936	59,070	1,212	2,110
	March	36,097	69,168	1,164	2,231
	April	94,746	73,543	3,158	2,451
	May	122,887	82,030	3,964	2,646
	June	124,064	75,451	4,135	2,515
	July	127,744	84,448	4,121	2,724
	August	135,886	97,066	4,383	3,131
	September	115,372	98,626	3,846	3,288
	October	112,149	96,090	3,618	3,100
	November	94,404	81,805	3,147	2,727
	December	81,289	90,592	2,622	2,922
2016	January	78,409	94,984	2,529	3,064
	February	73,896	93,320	2,548	3,218
	March	102,915	84,791	3,320	2,735
	April	82,871	79,929	2,762	2,664
	May	126,558	81,079	4,083	2,615
	June	44,141	70,681	1,471	2,356
	July	50,150	73,389	1,618	2,367
	August	51,546	81,902	1,663	2,642
	September	51,796	76,635	1,727	2,555
	October	51,190	82,171	1,651	2,651
	November	50,789	82,794	1,693	2,760
	December	47,211	72,354	1,523	2,334

Hilcorp Alaska, LLC
Grayling Platform
Projected Gas Distribution

Year	Month	Produced Gas (Mscf)	Imported Gas (Mscf)	Produced Gas (Mscfd)	Imported Gas (Mscfd)
2017	January	38,128	53,381	1,230	1,722
	February	33,952	68,154	1,213	2,434
	March	30,009	76,761	968	2,476
	April	33,769	74,295	1,126	2,477
	May	30,597	52,672	987	1,699
	June	28,387	46,816	946	1,561
	July	25,190	49,168	813	1,586
	August	25,567	46,934	825	1,514
	September	24,357	74,951	812	2,498
	October	34,196	75,300	1,103	2,429
	November	33,166	75,976	1,106	2,533
	December	27,851	84,552	898	2,727
2018	January	34,669	78,942	1,118	2,547
	February	27,760	62,240	991	2,223
	March	24,709	71,328	797	2,301
	April	29,057	68,182	969	2,273
	May	33,698	73,737	1,087	2,379
	June	33,591	54,751	1,120	1,825
	July	34,009	60,512	1,097	1,952
	August	42,755	80,160	1,379	2,586
	September	39,019	72,698	1,301	2,423
	October	31,750	89,980	1,024	2,903
	November	43,595	72,711	1,453	2,424
	December	40,369	80,065	1,302	2,583
2019	January	39,422	83,781	1,272	2,703
	February	38,333	78,143	1,369	2,791
	March	38,165	66,709	1,231	2,152
	April	41,290	77,375	1,376	2,579
	May	35,788	79,316	1,154	2,559
	June	37,851	72,801	1,262	2,427
	July	38,620	86,603	1,246	2,794
	August	39,041	81,116	1,259	2,617
	September	35,057	77,234	1,169	2,574
	October	41,014	72,448	1,323	2,337
	November	43,031	76,569	1,434	2,552
	December	41,761	80,026	1,347	2,581

Hilcorp Alaska, LLC
Grayling Platform
Projected Gas Distribution

Year	Month	Produced Gas (Mscf)	Imported Gas (Mscf)	Produced Gas (Mscfd)	Imported Gas (Mscfd)
2020	January	40,269	80,119	1,299	2,584
	February	37,454	73,341	1,292	2,529
	March	32,900	66,593	1,061	2,148
	April	32,335	50,547	1,078	1,685
	May	22,218	42,130	717	1,359
	June	25,891	44,230	863	1,474
	July	25,980	45,329	838	1,462
	August	25,405	42,765	820	1,380
	September	30,187	69,244	1,006	2,308
	October	30,547	70,097	985	2,261
	November	28,052	71,091	935	2,370
	December	32,784	66,947	1,058	2,160

Produced Gas System Design Capacity	2,100

Average 2011-2020	2,203
Standard Deviation 2011-2020	595
Projected Volume of Imported Gas (average + 1 std dev)	2,800
Total Projected Fuel Gas Consumption	4,900

COMPASS COMPRESSION

Hilcorp

UNIT	MODEL
C760	EM250-RAA2-2
DESIGN	
Site Details	50 ft @70 F
Inlet Gas	.7071 S.G. @120 F
Suction dP	0.0 psi
Discharge dP	5.5 psi

COMPRESSOR INFORMATION	
Make and Model	Ariel JGA/2
DRIVER INFORMATION	
Make and Model	Electric, WEG
Nominal Power Rating	250 HP @ 1800 rpm
Engine Derate / Motor S.F.	23 HP
Auxiliary Power	0 HP
Compressor Power	**227 HP @ 1800 rpm**

CYLINDERS				
Stage 1	Stage 2	Stage 3	Stage 4	Stage 5
(1) 11.000C	(1) 7.125C10	NA	NA	NA

COMMENTS
x
x

Please consult Compass Compression Services before operating outside performance envelope

Load Step Performance for Discharge Pressure = 260 PSIG

	Point Num	Discharge Pressure [psig]	Suction Pressure [psig]	Inlet Flow [mmscfd]	Power [hp]	Speed [rpm]	VVCP Stg1 [In]	VVCP Stg2 [In]	VVCP Stg3 [In]	VVCP Stg4 [In]	VVCP Stg5 [In]
Operating Range	1	260	40	1.925	213	1800	7.31 (V)	No Pkt	#N/A	#N/A	#N/A
	2	260	40	1.808	201	1800	14.62 (V)	No Pkt	#N/A	#N/A	#N/A
	3	260	50	2.211	221	1800	14.62 (V)	No Pkt	#N/A	#N/A	#N/A
	4	260	40	1.706	190	1800	21.93 (V)	No Pkt	#N/A	#N/A	#N/A
	5	260	50	2.097	211	1800	21.93 (V)	No Pkt	#N/A	#N/A	#N/A
	6	260	40	1.617	181	1800	29.24 (V)	No Pkt	#N/A	#N/A	#N/A
	7	260	50	1.998	201	1800	29.24 (V)	No Pkt	#N/A	#N/A	#N/A

Hilcorp

COMPASS
COMPRESSION

C760	
Site Details	50 ft @70 F
Inlet Gas	.7071 S.G. @120 F
Suction dP	0.0 psi
Discharge dP	5.5 psi

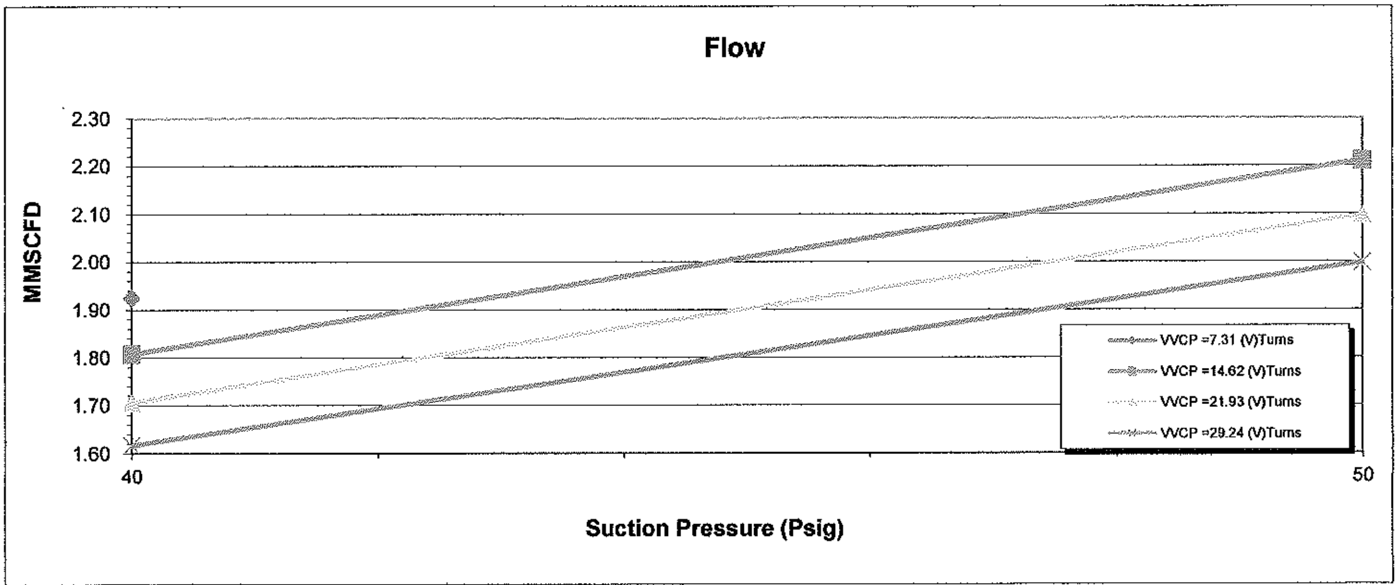
COMPRESSOR INFORMATION	
Make and Model	Ariel JGA/2
DRIVER INFORMATION	
Make and Model	Electric, WEG
Nominal Power Rating	250 HP @ 1800 rpm
Engine Derate / Motor S.F.	23 HP
Auxiliary Power	0 HP
Compressor Power	227 HP @ 1800 rpm

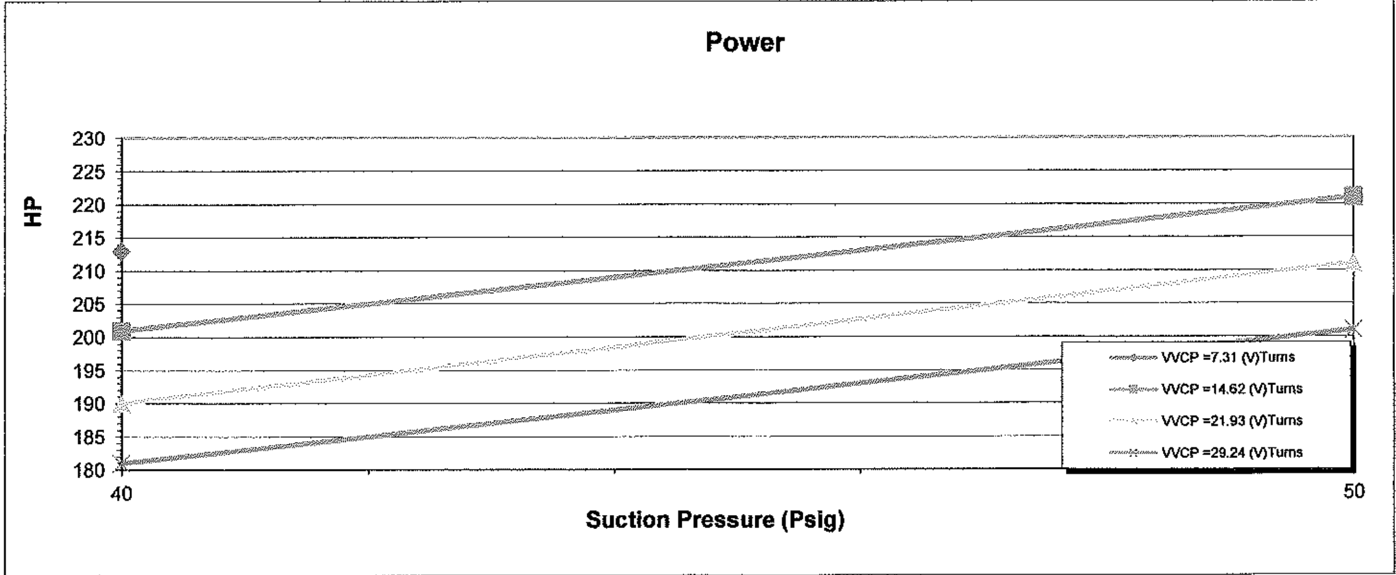
CYLINDERS				
Stage 1	Stage 2	Stage 3	Stage 4	Stage 5
(1) 11.000C	(1) 7.125C10	NA	NA	NA

COMMENTS
x
x

Please consult Compass Compression Services before operating outside performance envelope

Load Step Performance for Discharge Pressure = 260 PSIG





Appendix C Baseline Actual/ Projected Actual/ Potential Emissions Summary

Grayling Platform

Fuel Gas H_2S Increase Project
Construction Permit Application
Attachment B – Project Description, Emissions and Regulatory Review

Hilcorp Alaska, LLC

SLR Project No.: 105.00874.20026

October 2023

Hilcorp Alaska, LLC
Grayling Platform
Baseline SO_2 Emissions

Year	Month	Produced Gas (Mscf)	Imported Gas (Mscf)	Total Gas (Mscf)	H_2S (ppmv)	SO_2 (tons)	2-yr Avg SO_2 (tons)
2014	May	132,488	30,451	162,939	167	2.29	10.6
	June	104,672	48,965	153,637	216.3	2.8	11.8
	July	122,187	40,988	163,175	167.5	2.3	12.6
	August	111,043	42,060	153,103	142.6	1.84	13.1
	September	48,563	47,122	95,685	172.5	1.39	13.3
	October	34,086	57,326	91,412	194	1.49	13.1
	November	56,563	74,851	131,414	176.3	1.95	12.9
	December	41,529	60,589	102,118	200	1.72	13.2
2015	January	32,429	65,852	98,281	226	1.87	14
	February	33,936	59,070	93,006	232.5	1.82	14.7
	March	36,097	69,168	105,265	238.8	2.12	15.7
	April	94,746	73,543	168,289	185	2.62	16.8
	May	122,887	82,030	204,917	155	2.68	18.1
	June	124,064	75,451	199,515	187.5	3.15	19.7
	July	127,744	84,448	212,192	178.8	3.2	21.1
	August	135,886	97,066	232,952	162.5	3.19	22.7
	September	115,372	98,626	213,998	177.5	3.2	24.3
	October	112,149	96,090	208,239	174	3.05	25.5
	November	94,404	81,805	176,209	137.5	2.04	26.2
	December	81,289	90,592	171,881	185	2.68	27.4
2016	January	78,409	94,984	173,393	160	2.34	27.9
	February	73,896	93,320	167,216	115	1.62	27.6
	March	102,915	84,791	187,706	140	2.22	27.7
	April	82,871	79,929	162,800	140	1.92	27.8

2-year Average Maximum (tons) 27.9

Hilcorp Alaska, LLC
Grayling Platform
Projected Actual SO_2 Emissions

Year	Month	Produced Gas (Mscf)	Imported Gas (Mscf)	Produced Gas (Mscfd)	Imported Gas (Mscfd)
2011	January	101,909	63,537	3,287	2,050
	February	85,575	55,214	3,056	1,972
	March	92,052	66,993	2,969	2,161
	April	103,242	42,084	3,441	1,403
	May	101,593	41,569	3,277	1,341
	June	90,069	40,445	3,002	1,348
	July	88,442	54,019	2,853	1,743
	August	82,456	63,262	2,660	2,041
	September	77,312	67,103	2,577	2,237
	October	71,762	65,915	2,315	2,126
	November	67,009	67,596	2,234	2,253
	December	72,974	66,216	2,354	2,136
2012	January	74,790	67,332	2,413	2,172
	February	59,056	60,943	2,036	2,101
	March	64,929	65,988	2,094	2,129
	April	58,567	71,760	1,952	2,392
	May	55,792	83,639	1,800	2,698
	June	36,177	92,507	1,206	3,084
	July	29,991	106,402	967	3,432
	August	47,948	91,401	1,547	2,948
	September	45,797	90,492	1,527	3,016
	October	47,133	99,638	1,520	3,214
	November	73,771	103,279	2,459	3,443
	December	63,941	77,889	2,063	2,513
2013	January	59,140	45,460	1,908	1,466
	February	51,184	41,033	1,828	1,465
	March	20,812	68,297	671	2,203
	April	39,589	49,063	1,320	1,635
	May	30,261	44,642	976	1,440
	June	129,035	37,425	4,301	1,248
	July	131,418	31,961	4,239	1,031
	August	128,125	35,810	4,133	1,155
	September	127,092	28,901	4,236	963
	October	123,018	30,691	3,968	990
	November				
	December				

Hilcorp Alaska, LLC
Grayling Platform
Projected Actual SO_2 Emissions

Year	Month	Produced Gas (Mscf)	Imported Gas (Mscf)	Produced Gas (Mscfd)	Imported Gas (Mscfd)
2014	January	126,047	35,177	4,066	1,135
	February	117,493	35,298	4,196	1,261
	March	122,420	40,049	3,949	1,292
	April	114,871	34,522	3,829	1,151
	May	132,488	30,451	4,274	982
	June	104,672	48,965	3,489	1,632
	July	122,187	40,988	3,942	1,322
	August	111,043	42,060	3,582	1,357
	September	48,563	47,122	1,619	1,571
	October	34,086	57,326	1,100	1,849
	November	56,563	74,851	1,885	2,495
	December	41,529	60,589	1,340	1,954
2015	January	32,429	65,852	1,046	2,124
	February	33,936	59,070	1,212	2,110
	March	36,097	69,168	1,164	2,231
	April	94,746	73,543	3,158	2,451
	May	122,887	82,030	3,964	2,646
	June	124,064	75,451	4,135	2,515
	July	127,744	84,448	4,121	2,724
	August	135,886	97,066	4,383	3,131
	September	115,372	98,626	3,846	3,288
	October	112,149	96,090	3,618	3,100
	November	94,404	81,805	3,147	2,727
	December	81,289	90,592	2,622	2,922
2016	January	78,409	94,984	2,529	3,064
	February	73,896	93,320	2,548	3,218
	March	102,915	84,791	3,320	2,735
	April	82,871	79,929	2,762	2,664
	May	126,558	81,079	4,083	2,615
	June	44,141	70,681	1,471	2,356
	July	50,150	73,389	1,618	2,367
	August	51,546	81,902	1,663	2,642
	September	51,796	76,635	1,727	2,555
	October	51,190	82,171	1,651	2,651
	November	50,789	82,794	1,693	2,760
	December	47,211	72,354	1,523	2,334

Hilcorp Alaska, LLC
Grayling Platform
Projected Actual SO_2 Emissions

Year	Month	Produced Gas (Mscf)	Imported Gas (Mscf)	Produced Gas (Mscfd)	Imported Gas (Mscfd)
2017	January	38,128	53,381	1,230	1,722
	February	33,952	68,154	1,213	2,434
	March	30,009	76,761	968	2,476
	April	33,769	74,295	1,126	2,477
	May	30,597	52,672	987	1,699
	June	28,387	46,816	946	1,561
	July	25,190	49,168	813	1,586
	August	25,567	46,934	825	1,514
	September	24,357	74,951	812	2,498
	October	34,196	75,300	1,103	2,429
	November	33,166	75,976	1,106	2,533
	December	27,851	84,552	898	2,727
2018	January	34,669	78,942	1,118	2,547
	February	27,760	62,240	991	2,223
	March	24,709	71,328	797	2,301
	April	29,057	68,182	969	2,273
	May	33,698	73,737	1,087	2,379
	June	33,591	54,751	1,120	1,825
	July	34,009	60,512	1,097	1,952
	August	42,755	80,160	1,379	2,586
	September	39,019	72,698	1,301	2,423
	October	31,750	89,980	1,024	2,903
	November	43,595	72,711	1,453	2,424
	December	40,369	80,065	1,302	2,583
2019	January	39,422	83,781	1,272	2,703
	February	38,333	78,143	1,369	2,791
	March	38,165	66,709	1,231	2,152
	April	41,290	77,375	1,376	2,579
	May	35,788	79,316	1,154	2,559
	June	37,851	72,801	1,262	2,427
	July	38,620	86,603	1,246	2,794
	August	39,041	81,116	1,259	2,617
	September	35,057	77,234	1,169	2,574
	October	41,014	72,448	1,323	2,337
	November	43,031	76,569	1,434	2,552
	December	41,761	80,026	1,347	2,581

Hilcorp Alaska, LLC
Grayling Platform
Projected Actual SO_2 Emissions

Year	Month	Produced Gas (Mscf)	Imported Gas (Mscf)	Produced Gas (Mscfd)	Imported Gas (Mscfd)
2020	January	40,269	80,119	1,299	2,584
	February	37,454	73,341	1,292	2,529
	March	32,900	66,593	1,061	2,148
	April	32,335	50,547	1,078	1,685
	May	22,218	42,130	717	1,359
	June	25,891	44,230	863	1,474
	July	25,980	45,329	838	1,462
	August	25,405	42,765	820	1,380
	September	30,187	69,244	1,006	2,308
	October	30,547	70,097	985	2,261
	November	28,052	71,091	935	2,370
	December	32,784	66,947	1,058	2,160

Produced Gas System Design Capacity	2,100
Average 2011-2020	2,203
Standard Deviation 2011-2020	595
Projected Volume of Imported Gas (average + 1 std dev)	2,800
Total Projected Fuel Gas Consumption	4,900

H_2S (ppmv)	SO_2 (tons)
650	98.0

Grayling Platform

Fuel Gas H_2S Increase Project
Construction Permit Application

Attachment C – SO_2 Best Available Control Technology Review

Hilcorp Alaska, LLC

3800 Centerpoint Drive, Suite 1400, Anchorage, Alaska, 99503

Prepared by:

SLR International Corporation

2700 Gambell Street, Suite 200, Anchorage, Alaska, 99503

SLR Project No.: 105.00874.20026

October 2023

Grayling Platform
Fuel Gas H_2S Increase Project
Construction Permit Application
Attachment C – SO_2 Best Available Control Technology Review

Prepared for:

Hilcorp Alaska, LLC
3800 Centerpoint Drive, Suite 1400
Anchorage, AK 99503

This document has been prepared by SLR International Corporation (SLR). The material and data in this report were prepared under the supervision and direction of the undersigned.

Jeff Alger
Principal Engineer

Sims Duggins
Senior Principal

TA DAMIANA

Tom Damiana
Principal Engineer

Table of Contents

C1. Project Description C1-1
C2. BACT Methodology C2-1
  C2.1 General C2-1
  C2.2 Cost Analysis Methodology C2-5
    C2.2.1 General C2-5
    C2.2.2 Capital Costs C2-5
    C2.2.3 Annualized Costs C2-6
C3. BACT Analysis for SO_2 and $PM_{2.5}$ C3-1
  C3.1 RACT/ BACT/ LAER Clearinghouse Review C3-1
  C3.2 Availability of SO_2 Control Technologies C3-1
    C3.2.1 Add-On Flue Gas Treatment Control (Flue Gas Desulfurization) C3-2
    C3.2.2 Fuel Gas Treatment Controls C3-2
  C3.3 Technical Feasibility of SO_2 Controls C3-3
    C3.3.1 Add-On Flue Gas Control (Flue Gas Desulfurization) C3-4
    C3.3.2 Fuel Gas Treatment Controls C3-4
  C3.4 Top-Down Evaluation of Controls C3-6
    C3.4.1 Liquid Redox (LO-CAT®) C3-6
    C3.4.2 THIOPAQ® Bio-Desulfurization C3-11
    C3.4.3 Solid Scavenger C3-15
    C3.4.4 Liquid Scavenger C3-19
    C3.4.5 Summary and Conclusions C3-20
C4. References C4-1

Tables

Table C2-1: Grayling Platform Capital Cost Factors C2-8
Table C2-2: Grayling Platform Annualized Cost Factors C2-9
Table C3-1: Grayling Platform Emissions Units C3-1
Table C3-2: SO_2 Control Technologies C3-2
Table C3-3: Technical Feasibility of SO_2 Control Technologies C3-6
Table C3-4: Grayling Platform LO-CAT® Capital Costs C3-9
Table C3-5: Grayling Platform LO-CAT® Annual Costs C3-10
Table C3-6: Grayling Platform THIOPAQ® Capital Costs C3-13
Table C3-7: Grayling Platform THIOPAQ® Annual Costs C3-14
Table C3-8: Grayling Platform SulfaTreat® Capital Costs C3-16
Table C3-9: Grayling Platform SulfaTreat® Annual Costs C3-18
Table C3-10: Grayling Platform Liquid Scavenger Annual Costs C3-20
Table C3-11: Grayling Platform SO_2 Cost Effectiveness Summary C3-20

Figures

Figure C2-1: Top Down Decision Making Process C2-4
Figure C3-1: Sulfur Removal Technologies C3-4

Appendices

Appendix A RACT/ BACT/ LAER
Appendix B Vendor Data
Appendix C Support Data

C1. Project Description

Hilcorp Alaska, LLC (Hilcorp) owns and operates the Grayling Platform (Grayling) located in Upper Cook Inlet, Alaska. Hilcorp Alaska, LLC (Hilcorp) owns and operates the Grayling Platform (Grayling) located in Upper Cook Inlet, Alaska. Grayling is an offshore oil and gas production platform, producing gas and oil with some residual water in the oil. The platform currently burns all its produced gas in platform combustion devices and imports sweet gas from the Steelhead Platform to make up any shortages in gas supply. The two gas streams are comingled prior to being introduced into the fuel gas system on the platform.

Hilcorp submitted an air quality permit application to the Alaska Department of Environmental Conservation (ADEC) in 2018, which included, in part, a request to increase the Grayling fuel gas H_2S air quality protection limit from 250 ppmv to 400 ppmv. In response to that application, ADEC issued to Hilcorp Air Quality Control Minor Permit no. AQ0069MSS04 on February 14, 2019 for the Grayling Platform stationary source with the fuel gas H_2S limit set at 400 ppmv. One purpose of this application is to request an increase in the existing 400 ppmv monthly average stationary-source wide fuel gas H_2S content limit found in permit no. AQ0069MSS04, Revision 1, which is set as an ambient air quality protection limit. (See Condition 9 of the permit, found in **Attachment G** to this application.) Ambient air quality modeling and the air quality-related values analysis provided in **Attachment F** of this application demonstrate that the existing limit can be increased while still protecting ambient air quality and that the impact of the requested limit increase on the State's regional haze reasonable further progress goals for Class I areas is inconsequential.

This application also includes an analysis of Best Available Control Technology (BACT) because the change in actual emissions (comparing projected actual emissions to baseline actual emissions) associated with the proposed increase in the fuel gas H_2S content limit triggers review under the Prevention of Significant Deterioration (PSD) air quality permitting program as detailed in **Attachment B** of this application. Details of the BACT analysis are provided in **Attachment C** of this application.

Specifically, and in summary, with this application Hilcorp requests an increase of the short-term (i.e., monthly average) permitted fuel gas H_2S limit to 1,250 ppmv to protect ambient air quality and proposes to establish a BACT limit of 98 tons per year (tpy) of sulfur dioxide (SO_2) emissions based on an annual average fuel gas H_2S concentration of 650 ppmv. (See **Attachment B** of this application for details regarding the basis for the proposed fuel gas H_2S limits.)

This action is hereinafter referred to as the "Grayling Platform Fuel Gas H_2S Increase Project" or "the Project."

No emissions units will be added or modified as part of the Project.

C2. BACT Methodology

BACT is typically performed on individual units. As described in **Attachment B** of this application, the Project addresses the H_2S content of a comingled fuel gas stream where only the produced gas needs treatment. Since the comingled fuel gas feeds all combustion devices on the Grayling Platform, this BACT analysis addresses the produced gas rather than the individual combustion devices. The baseline SO_2 emissions associated with the produced gas are calculated using the following equation.

$$SO_2 = \frac{Q_{pg}*H_2S * 64 * 365}{379.6 * 1{,}000 * 2{,}000}$$

where:

SO_2 is sulfur dioxide emissions expressed in units of tons per year generated by the produced gas.

Q_{pg} is the design capacity of the produced gas based on booster compressor design = 2,100 Mscfd.

H_2S is the maximum expected hydrogen sulfide concentration in the produced gas = 1,400 ppmv.

64 is the molecular weight of SO_2.

365 is the number of days per year.

379.6 is the volume (standard cubic feet) of gas per mole of gas at 14.696 psia and 60°F.

1,000 is the factor to convert from Mscf to MMscf.

2,000 is the factor to convert from lbs to tons.

$$SO_2 = \frac{2{,}100 * 1{,}400 * 64 * 365}{379.6 * 1{,}000 * 2{,}000} = 90.5 \text{ tons/year}$$

C2.1 General

BACT applies to each individual emissions unit affected by the proposed change. Individual BACT determinations are performed for each pollutant subject to a Prevention of Significant Deterioration (PSD) review. The BACT requirements are intended to ensure that a proposed new or modified major stationary source incorporates controls that represent the maximum degree of emissions reduction achievable considering energy, environmental and economic impacts, and other costs. BACT is defined in 40 C.F.R. 51.166(b)(12) as adopted by 18 AAC 50.040(h) as follows:

> “an emissions limitation based on the maximum degree of reduction for each regulated NSR pollutant … taking into account energy, environmental, and economic impacts and other costs … through application of production processes or available methods, systems, and techniques… for control of such pollutant… If the reviewing authority determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction

> achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

The structure of the BACT analysis is illustrated graphically in **Figure C2-1**. This approach reflects the "top down" BACT guidance (USEPA 2019) typically employed by the United States Environmental Protection Agency (USEPA) and Alaska Department of Environmental Conservation (ADEC) for PSD determinations.

Step 1: Identify All Control Technologies

The first step in a "top-down" BACT analysis is to identify all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

Air pollution control technologies and techniques include the application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. The control alternatives must include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies. Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives, usually representing the top alternative.

Step 2: Eliminate Technically Infeasible Options

In the second step, the technical feasibility of each control option identified in step one is evaluated with respect to source-specific factors. A demonstration of technical infeasibility must be clearly documented and show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis. For example, in some cases the level of control in a permit is not achieved in practice (e.g., a source has received a permit, but the project was canceled, or every operating source at the permitted level has been physically unable to achieve compliance with the limit). If supporting documentation has been provided to show why such limits are not technically feasible, then the level of control (but not necessarily the technology) may be eliminated from further consideration.

Step 3: Rank Remaining Technologies by Control Efficiency

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of over-all control effectiveness for the pollutant under review, with the most effective control alternative at the top.

Step 4: Evaluate Most Effective Controls and Document Results

After identification of available and technically feasible control technology options, the energy, environmental, and economic impacts are considered to arrive at the final level of control.

The analysis presents the associated impacts of the most stringent control option in the listing. Both beneficial and adverse impacts are discussed and quantified where possible. In general, the BACT analysis focuses on the direct impact of the control alternative.

The analysis must consider whether impacts of unregulated air pollutants or non-air impacts such as liquid, solid, or hazardous waste disposal impacts would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended, and the results proposed as BACT. If the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that the alternative is inappropriate as BACT. The most effective control option not eliminated is proposed as BACT for the pollutant and emissions unit under review. In no case can a BACT determination be proposed that would exceed an applicable New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (NESHAP) emission limit (40 C.F.R. Parts 60, 61, and 63).

The energy impact analysis estimates the direct energy impacts of the control alternatives in units of energy consumption (e.g., Btu, kW-hr, barrels of oil, tons of coal, etc.). Electrical, steam, fuel, and other utility requirements are quantified. In addition, since some of the control options generate hazardous waste, the hazardous waste disposal cost is debited to the net control cost.

The economic impact analysis involves assessing the costs associated with installation and operation of each BACT alternative. Examples of costs that are included are: 1) capital and interest charges, 2) engineering and installation costs, 3) operating and maintenance labor and materials, 4) energy costs, 5) waste disposal costs, and 6) lost revenue due to equipment downtime. Credit for tax incentives, product recovery costs, and byproduct sales generated from the use of control systems are included where applicable.

As a guide in determining excessive control costs, alternative control systems are compared in terms of certain cost effectiveness ratios. Such ratios include the following:

- Cost per unit of pollution removed (for example, dollars per ton per year);
- Unit production costs (for example, costs per unit of product); and
- Cost per dollar of total sales.

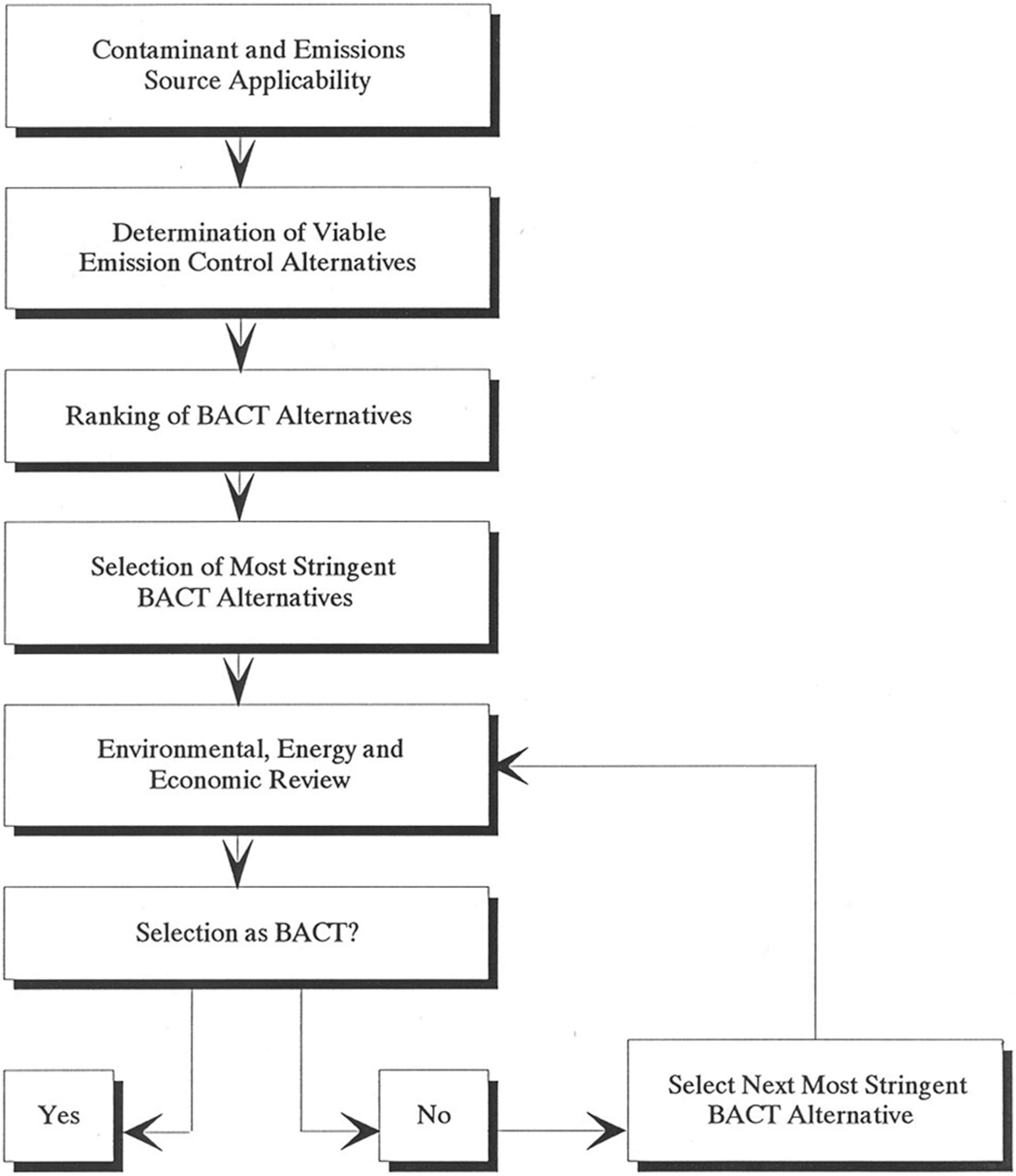
The BACT analysis submitted with this application utilizes cost per ton of pollutant removed per year as the applicable measure of cost effectiveness.

Step 5: Select BACT

The determination of what is economically feasible is a subjective, case-by-case assessment by the regulatory agency. The objective is to establish an acceptable level of cost impact. As such, the cost impact (dollars per ton per year of emissions reduced) determined to be economically feasible can simply be the value that another similar process operation agreed to spend.

Details on the cost estimating procedures utilized are outlined below.

Figure C2-1: Top Down Decision Making Process



C2.2 Cost Analysis Methodology

C2.2.1 General

The basis for comparison in the economic analysis of the control scenarios is the cost effectiveness; that is, the value obtained by dividing the total net annualized cost by the tons of pollutant removed per year for each control technique. Annualized costs include the annualized capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, and such maintenance costs as replacement parts, overhead, raw materials, and utilities. Capital costs include both the direct cost of the control equipment and all necessary auxiliaries as well as both the direct and indirect costs to install the equipment. Direct installation costs include costs for supports, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include costs for engineering and supervision, construction expenses, start-up costs and contingencies. Capital and annualized cost components are shown in **Table C2-1** and **Table C2-2**, respectively.

To accurately estimate the total annualized cost of a particular control technology, a conceptual design must be developed in sufficient detail to quantify all the direct capital and operating costs. All costs are then expressed as an annualized cost as well as calculated cost-effectiveness values. This approach of amortizing the investment into equal end-of-year annual costs is termed the Equivalent Uniform Annual Cost (EUAC) (Grant and Ireson 1976). It is very useful when comparing the costs of two or more alternative control systems and is the USEPA-recommended method of estimating control costs. The EUAC costs and estimating methodology used in this report are directed toward a "study" estimate of ±30 percent (%) accuracy that is described in the USEPA's OAQPS Control Cost Manual (USEPA 2002). According to the Chemical Engineer's Handbook (Perry and Chilton 1984), a study estimate is "...used to estimate the economic feasibility of a project before expending significant funds for piloting, marketing, land surveys, and acquisition... [however] it can be prepared at relatively low cost with minimum data." The capital and annual cost estimating methodologies are described below.

Due to the age of the platform, there may be unique size and weight distribution considerations that have not been considered and could entail a major design effort to accommodate new equipment. To reflect these unknowns, Hilcorp has included an additional retrofit factor of 50%.

C2.2.2 Capital Costs

A number of methods with varying degrees of accuracy are available for estimating capital costs of pollutant control devices. Cost estimating techniques range from the simple "survey method" whereby the total installed costs are equated to a basic operating parameter (e.g., gas flow rate) to detailed cost estimates based on preliminary designs, systems drawings, and contractor quotes. Survey method cost algorithms are derived from industry surveys of overall capital costs of installed equipment and represent the average cost of many installations. Since there are no provisions that permit normalization of the many site-specific parameters which affect both equipment and installation costs, survey methods provide accuracy, at best, on the order of +50 percent to -30 percent (Vatavuk and Neveril 1980).

The capital cost factors used for this BACT review are given in **Table C2-1**. These represent a combination of average factors based on USEPA BACT guidance and labor adjustment factors developed by Worley Parsons. The purchased equipment includes basic equipment and auxiliaries, instrumentation and controls, module, freight, and taxes. Freight includes truck transport from the vendor’s locations to OSK Dock in Nikiski, Alaska, and barge shipment from

OSK to the Grayling Platform. The construction costs address labor involved in the project. Construction hours are based on labor for construction in the lower 48 States. The hours are adjusted to account for experience factor, economy – availability of labor, project type, shutdown requirements, construction type, climate conditions, location, and density. The labor adjustment factors used for Alaska offshore construction are provided in **Appendix C** to this section of the application.

Indirect capital costs associated with construction include engineering and procurement, and unit operator costs (UOC). The licensing fee is included with the vendor's quote. Items included in the UOC are Hilcorp's project team, operation and maintenance personnel, safe-out, work permits, construction coordination and support, and start-up.

C2.2.3 Annualized Costs

As shown in **Table C2-2**, annualized costs are comprised of the direct operating costs of materials and labor for maintenance, operation, supervision, utilities and waste disposal, and the indirect operating charges, including plant overhead, general and administrative, and capital charges. These generalized factors may in some cases be modified to provide more accurate, site-specific values. This is discussed further in the BACT analysis when examining costs of each control option.

Labor and material costs for operation, supervision, and maintenance vary, depending on the system type, degree of system automation, and operating time. Operating labor is generally reduced with increased system automation. Maintenance labor is estimated at 110 percent of operating labor. The hourly rate for labor includes basic wages and overhead charges such as benefits, overtime, transportation costs to and from the platform, and food and lodging while on the platform. The basic wages were taken from the Bureau of Labor Statistics (BLS 2019a). An adjustment to the labor rate was made to account for inefficiencies associated with work at remote locations using a study conducted by Worley Parsons. A description of the contributors to this adjustment factor is found in **Appendix C** to this section of the application. Employer costs for benefits were obtained from a BLS news release (BLS 2019b). Since the benefits in BLS 2019b are based on a percentage of the total compensation, they have been adjusted for use in this application to reflect the cost based on a percentage of the wages. A breakdown of the costs that make up the labor rate is provided in **Appendix C** to this section of the application. The resulting labor rate used in this BACT analysis is $96 per hour.

Utility costs for the control device and auxiliary equipment are based on the total annual consumption, unit costs, and vendor estimates. The cost of electrical power is based on $0.094 per kilowatt per hour (kW-hr). This cost includes the cost of operating and maintaining the gas turbines that provide power for the platform. A breakdown of the hourly costs is provided in **Appendix C** to this section of the application.

Indirect operating costs include the cost of plant overhead, general and administrative (G&A), and capital charges. G&A, as shown in **Table C2-2**, is a direct function of the total capital cost. Overhead is a function of both labor (payroll and plant) and project capital cost. The capital recovery cost, or capital charge, is based on the operational life of the system, interest and capital depreciation rates, and total capital cost. These charges are based on the capital recovery factor (CRF) defined as:

$$CRF = i (1 +i)^n / [(1 + i)^n - 1]$$

where:

i = the annual interest rate; and
n = equipment life (years).

For this economic analysis, the capital recovery factor was calculated as 0.12329, which assumes that the equipment life is 10 years and the average annual interest rate is 4 percent. The annual interest rate was calculated based on guidelines used by the California Air Resources Board. (BAAQMD 2015) It involves using the 10-Year Treasury Note interest rate (yield) averaged over a six-month period prior to the Covid-19 pandemic, adding two percentage points and rounding up to the next higher integer rate.

Based on the above cost estimating procedures, capital and annualized costs have been estimated for each BACT emission control alternative studied. These costs are budgetary estimates, provided for comparative purposes only, and are not final costs. The estimated capital and operating costs do not include all components that are encountered in a project of this nature; therefore, the costs presented are conservative. Specific capital and annualized cost calculations (if applicable) are discussed in the BACT evaluations.

The basis for comparing the economic impacts of control scenarios is cost effectiveness. This value is defined as the total net annualized cost of control, divided by the tons of pollutant removed per year, for each control technique. Annualized costs include the capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, replacement parts, overhead, raw materials, waste disposal and utilities. Capital costs include both the direct and indirect costs of installing the equipment. Direct installation costs include costs for erection, electrical, piping, and insulation, painting. Indirect installation costs include costs for engineering and supervision, construction expenses, startup costs and contingencies.

Table C2-1: Grayling Platform Capital Cost Factors

Direct Costs		
1) Purchased Equipment		
a) Basic Equipment and Auxiliaries **(A)**		Vendor
b) Instrument and Controls	0.10 * (A)	EPA Cost Control
c) Spare Parts	0.02 * (A)	EPA Cost Control
d) Freight	0.10 * (A)	EPA Cost Control
e) Taxes	0.03 * (a + b + c)	
Total Purchased Equipment Costs **(B)**	a + b + c + d + e	
2) Platform Construction Costs		
a) Supports	0.08 * (A)	EPA Cost Control
b) Erection and Handling	0.14 * (A)	EPA Cost Control
c) Instrumentation	0.02 * (A)	EPA Cost Control
d) Electrical	0.04 * (A)	EPA Cost Control
e) Piping	0.02 * (A)	EPA Cost Control
f) Insulation	0.01 * (A)	EPA Cost Control
g) Painting	0.01 * (A)	EPA Cost Control
Total Construction Cost **(C)**	a + b + c + d + e + f + g	
Total Direct Costs (TDC)	(B) + (C)	
Indirect Costs		
3) Engineering and Procurement	0.19 * (A)	Worley Parsons
4) Unit Operator Costs (UOC)	0.13 * TDC	Worley Parsons
5) Start-up	Included in UOC	
6) Performance Test	0.015 * (B)	
7) License Fee		Vendor Detail
Total Indirect Costs (IDC)	4 + 5+ 6 + 7 + 8	
Total Direct Costs + Indirect Costs	(TDC + IDC)	
8) Contingency (30% of TDC + IDC)	0.3 * (TDC + IDC)	
9) Retrofit Factor (50% of TDC + IDC)	0.5 * (TDC + IDC)	
Total Capital Costs (TCC)	TDC + IDC + Contingency + Retrofit	

Table C2-2: Grayling Platform Annualized Cost Factors

Direct Costs	
1) Operating Labor	$96/hr
2) Supervisory Labor	15 percent of operating labor
3) Maintenance Labor	$96/hr
4) Parts and Materials	100 percent of maintenance labor
5) Utilities	
a) Electricity	$0.094/kW-hr
6) Chemicals	Equipment Dependent
Indirect Costs	
7) Overhead	Included with operating and maintenance hourly rate
8) Property Tax	1 percent of Total Capital Cost (TCC)
9) Insurance	1 percent of TCC
10) G&A Charges	2 percent of TCC
11) Capital Recovery	CRF * Total Capital Cost where CRF = 0.12329 (10-year life; 4 percent rate of return [ROR])

Source: USEPA 2002; Vatavuk and Neveril 1980.

C3. BACT Analysis for SO_2 and $PM_{2.5}$

This section outlines the various components of the BACT review completed for SO_2 emissions associated with the Project. As noted in **Section B3.1.1 of Attachment B** of this application, SO_2 is a precursor to particulate matter less than 2.5 microns in diameter ($PM_{2.5}$) and, as a result, when PSD applicability is triggered for SO_2, it also is indirectly triggered for $PM_{2.5}$. Indirect triggering of PSD permitting for $PM_{2.5}$ by the Project means that the SO_2 BACT analysis presented herein serves as a surrogate for a $PM_{2.5}$ BACT analysis.

C3.1 RACT/ BACT/ LAER Clearinghouse Review

On the Grayling Platform, the produced gas and imported gas are comingled prior to being routed to any of the platform emissions units. However, the search for applicable control technologies was based on the equipment listed in **Table C3-1**.

Table C3-1: Grayling Platform Emissions Units

EU ID	Unit Type
1, 2 & 4	Gas fired Solar Centaur Turbines
14, 15, 16, 17, & 18	Gas fired Solar Saturn Turbines
19 & 20	Gas fired Continental Boilers
31	Solar Taurus Turbine

A search of USEPA RACT/ BACT/ LAER Clearinghouse (RBLC) (USEPA 2020) was conducted for SO_2 for the following process types:

- Simple Cycle Gas Turbines of 25 MW or less – Process Types 16.110 and 16.150
- Boilers of 100 MMBtu/hr or less – Process Types 13.310 and 13.390

The search was conducted for the time period between January 2010 and May 2020. A total of five BACT determinations were found for gas-fired turbines and 69 BACT determinations for heaters. Results of the search are provided in **Appendix A** to this section of the application. Where a control method was listed, it was found to be low sulfur fuel or pipeline quality natural gas. Where no control method was listed, BACT was determined to be based on the available fuel quality.

C3.2 Availability of SO_2 Control Technologies

Available SO_2 control technologies are summarized in **Table C3-2**. These technologies include add-on flue gas controls or fuel treatment. Add-on flue gas controls treat exhaust streams to remove SO_2. Fuel treatment uses processes that are aimed at removing H_2S from the fuel prior to combustion. This approach eliminates the formation of SO_2.

Table C3-2: SO_2 Control Technologies

Flue Gas Desulfurization
LO-CAT®
THIOPAQ®
H_2S Scavengers (Solid or Liquid)
Adsorption Process (Amine treatment)
Seawater Scrubbing

C3.2.1 Add-On Flue Gas Treatment Control (Flue Gas Desulfurization)

Add-on flue-gas control technologies for scrubbing SO_2 from the exhaust gas include both wet and dry flue gas desulfurization (FGD) systems. In a wet system, flue gas is accelerated through a nozzle and deluged with scrubbing liquid. Sodium hydroxide (NaOH) is injected into the scrubber liquid. When the scrubbing liquor comes into contact with sulfur dioxide in the flue gas, the sulfur dioxide is converted to sodium sulfate (Na_2SO_4) which is then removed from the aqueous stream. In a dry system, SO_2 in the flue gas reacts directly with lime to form solid calcium sulfate ($CaSO_4$). The spent solids must then be collected by either a baghouse or an electrostatic precipitator.

Another form of flue gas desulfurization involves the use of seawater to treat the exhaust products from each of the combustion devices. In this method, exhaust products are ducted to an absorber unit where seawater is introduced in a manner that provides intensive contact with exhaust gases to ensure mass transfer from the gaseous into the liquid phase. The seawater exiting the absorber must be treated to control the acidity.

C3.2.2 Fuel Gas Treatment Controls

Available methods of controlling fuel gas inlet stream H_2S levels include liquid redox (LO-CAT®), THIOPAQ® Bio-Desulfurization, H_2S scavenging (solid or liquid), adsorption, and seawater scrubbing.

C3.2.2.1 Liquid Redox (LO-CAT)

The liquid redox process employs an aqueous based solution typically containing metal ions, usually iron, which are capable of transferring electrons in reduction-oxidation (redox) reactions. A commercial application offered by Merichem is called the LO-CAT® process. The sour gas is introduced into a contactor vessel flowing counter current with a chelated iron catalyst solution. Saturated sweet gas exits the top of the contactor. H_2S is absorbed into the catalyst solution and routed to an oxidation vessel where air is bubbled through the solution. The oxidation vessel regenerates the chelated iron catalyst for recirculation to the absorption contactor and produces a sulfur by-product that can be de-watered and sent to a landfill for disposal.

Access to high purity fresh water is necessary to operate the LO-CAT® system to continually replenish the LO-CAT® liquid. The LO-CAT® liquid loses water to the fuel gas in the countercurrent absorption tower and to the sulfur by-product during filtering. The replenished water must be extremely pure to avoid destroying the activity of the liquid catalyst solution. A reverse osmosis unit would be required for this option to convert potable water to high purity water. The sweet fuel gas from the LO-CAT® process must be dried to prevent condensation of liquids in the control valves.

C3.2.2.2 THIOPAQ® Bio-Desulfurization Technology

THIOPAQ® Bio-Desulfurization is a biotechnological process for removing H_2S from gaseous streams by absorption into a mild alkaline solution followed by the oxidation of the absorbed sulfide to elemental sulfur by naturally occurring microorganisms. In the THIOPAQ® process, a gas stream containing H_2S contacts an aqueous soda solution containing thiobacillus bacteria in an absorber. The soda absorbs the H_2S and is transferred to a flash vessel to remove dissolved hydrocarbon gases that become entrained in the spent scrubber solution. From the flash vessel, the solution is routed to an aerated atmospheric tank where the bacteria biologically convert the H_2S to elemental sulfur. Regenerated solvent from the bioreactor is pumped back to the scrubber for reuse. The biological sulfur slurry produced may be disposed of in a landfill or purified to a high-quality sulfur cake. The application range is from approximately 200 pounds (lbs) per day to 40 tons of sulfur per day.

C3.2.2.3 H_2S Scavenging (Solid or Liquid)

The scavenging process can be accomplished with either solid or liquid scavengers that have non-regenerable reaction systems. Solid scavengers are generally iron-based materials. The most common systems are marketed under SulfaTreat® and Sulfa-Rite® and both use an iron oxide scavenger. Fuel gas is routed through a vessel containing the solid scavenger and the H_2S is chemically changed into a safe and stable compound, iron pyrite (FeS_4). Optimum performance of the scavenger requires that the fuel gas be 100 percent saturated before entering the vessel. The optimum liquid scavenger has been found to be methyl - triazine. The scavenger is water soluble and has less of a tendency to build up deposits. The scavenger liquid is typically injected directly into the gas stream using a static mixer, contact vessel, or long length of pipe. The efficiency of the system is dependent on the degree of mixing and is, therefore, sensitive to flow fluctuations.

C3.2.2.4 Adsorption Process

The adsorption process includes amine treatment of sour gas. In this process, sour gas is routed through a packed or trayed contactor, which contains a liquid amine solution that absorbs the H_2S. Sweetened fuel gas exits the top of the contactor. The rich amine is heated in a reboiler and routed to a still column where the amine is regenerated and an acid gas containing H_2S is generated. Acid gases can be routed to flare, but this approach would not reduce the SO_2 being released to the atmosphere. To reduce SO_2, acid gases must be routed to either an H_2S scavenging system, LO-CAT® or THIOPAQ® process for sulfur recovery.

C3.2.2.5 Seawater Scavenging

Hydrogen sulfide can be removed from a fuel gas stream via absorption and disassociation utilizing a seawater contact system of scrubbers. Using this technology, fuel gas and seawater pass through a tower in which the fuel gas scrubs oxygen from the seawater and the seawater scrubs H_2S from the fuel gas.

C3.3 Technical Feasibility of SO_2 Controls

This section describes the technical feasibility of implementing available exhaust gas SO_2 controls and/or fuel gas H_2S treatments.

C3.3.1 Add-On Flue Gas Control (Flue Gas Desulfurization)

FGD technology is typically used in conjunction with high sulfur fuels such as coal and oil. A search of the RACT/ BACT/ LAER Clearinghouse did not identify any add-on controls as a requirement of any RACT/ BACT/ LAER analyses for gas-fired turbines. Due to the relatively low concentration of SO_2 in the exhaust (approximately 36 ppmvd) and limited space available on the platform, any type of add-on FGD control is not technically feasible.

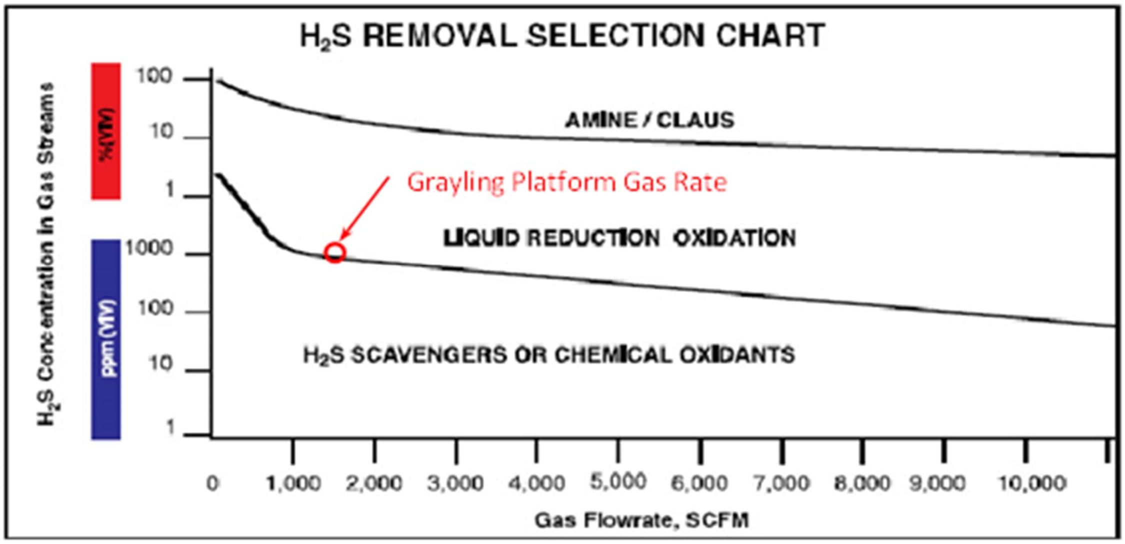
The use of a seawater FGD technology has the same shortcomings as a standard FGD system, but the seawater FGD system must also contend with the high silt content of Cook Inlet seawater which would require additional treatment to avoid plugging of the system.

Therefore, no further consideration will be given to add-on flue gas (exhaust) controls for the Grayling Platform.

C3.3.2 Fuel Gas Treatment Controls

A first step in identifying feasible technologies to treat fuel gas has been provided by Gas Technology Products, LLC showing general industry guidance on H_2S removal. **Figure C3-1** plots where the various technologies fall when considering gas flowrates and H_2S concentrations. The Grayling Platform gas flowrate to be controlled is approximately 1,458 standard cubic feet per minute (scfm) or 2.1 million standard cubic feet per day (MMscfd). The plot shows that Grayling Platform is marginal for liquid reduction oxidation processes and on the high side for scavengers.

Figure C3-1: Sulfur Removal Technologies



C3.3.2.1 Liquid Redox (LO-CAT)

The LO-CAT® process converts H_2S to elemental sulfur using a patented, dual chelated iron catalyst which has been shown to be environmentally safe.

The LO-CAT® process has achieved H_2S removal efficiencies of greater than 99 percent in many different applications and industries with gas flowrates ranging in size from a few standard cubic feet per minute to several hundred million standard cubic feet per day and from a few pounds of sulfur produced to greater than 20 metric tons of sulfur produced each day. The sour gas entering a typical LO-CAT® system installation contains anywhere from 100 ppmv H_2S to 100 percent H_2S. Application of this technology is technically feasible for the Grayling Platform.

C3.3.2.2 THIOPAQ® Technology

The THIOPAQ® process is an environmentally friendly biological process for H_2S removal from sour gas streams and recovery as elemental sulfur. The most unique aspect of the process is that it utilizes a living biocatalyst to oxidize H_2S to elemental sulfur. The biocatalyst belongs to the group of naturally occurring colorless sulfur oxidizing organisms. These are autotropic organisms, which means that carbon dioxide is required as their sole carbon source. The biocatalyst is fast growing and highly resistant to varying process conditions. The energy needed for growth is obtained from the sulfide oxidation process. These organisms are naturally occurring and are not genetically manipulated or modified. The application of this technology is technically feasible for the Grayling Platform.

C3.3.2.3 H_2S Scavenger (Solid or Liquid)

This technology is designed to sweeten gas streams containing low levels of H_2S. SulfaTreat® is designed to achieve >98 percent reduction in SO_2 emissions. It is expected to achieve 99 percent reduction in SO_2 emissions. Both solid and liquid scavengers require that the incoming gas stream be saturated for proper scavenger activity. It is anticipated that water will need to be added to the incoming gas stream. To avoid the potential for degradation in the reduction process from impurities in the raw water, a water treatment system must be included as part of the control option. Application of solid or liquid scavenger is technically feasible for the Grayling Platform.

C3.3.2.4 Adsorption Process (Amine Treatment)

One typical solvent adsorption process is amine sweetening, utilizing ethanolamine solvent such as MEA, MDEA, and DEA. An amine system is composed of an absorber tower and adsorption gas dehydration. Amine treatment, as a standalone technology, will not reduce the amount of sulfur dioxide released to the atmosphere. Regeneration of the amine solution will produce a sour gas stream that is rich in H_2S. If this gas is directed to the flare for destruction, the SO_2 will be released from the flare rather than the other combustion devices. To avoid releasing the SO_2, additional treatment must be included on the sour gas stream to eliminate the H_2S. The costs associated with these systems are significant making it highly unlikely that this technology would be cost effective. Amine treatment will not be considered further for the Grayling Platform.

C3.3.2.5 Seawater Scrubbing

Seawater scrubbing can potentially be a feasible method of reducing H_2S in the inlet fuel gas streams at locations where seawater is readily available (e.g., offshore platforms, seawater treatment plants, etc.). The Kuparuk Seawater Treatment Plant (KSTP) is currently using fuel gas to de-aerate seawater used in enhanced oil recovery. In the process of de-aerating seawater, fuel gas is stripped of H_2S and the fuel becomes saturated. While the system has been effective at scrubbing H_2S, the saturated off-gas contains trace metals such as sodium.

Scrubbing fuel gas with seawater introduces contaminants and moisture into the fuel gas, mandating additional fuel gas dehydration, new metallurgy throughout the gas lines, and replacement of the turbine blades. Hilcorp believes H_2S seawater scrubbing is not a technically feasible BACT option due to the inability of the turbines to handle fuels with high sodium content. Therefore, this technology was eliminated from further consideration as potential BACT for fuel gas H_2S control on the Grayling Platform.

C3.3.2.6 Summary of Control Technology Feasibility

Table C3-3 summarizes the technical feasibility of potential SO_2 control technologies for use at the Grayling Platform.

Table C3-3: Technical Feasibility of SO_2 Control Technologies

Controls	Comments	Technically Feasible?
Flue Gas Desulfurization	Not feasible for gas fired turbines. Limited space available on a platform.	No
LO-CAT®	--	Yes
THIOPAQ®	--	Yes
H_2S Scavengers (Solid or Liquid)	--	Yes
Adsorption Process (Amine treatment)	Does not prevent SO_2 from being released to the atmosphere without an additional acid gas stream treatment system.	No
Seawater Scrubbing	Corrosion problems with turbine blading.	No

C3.4 Top-Down Evaluation of Controls

The technology assessment above identifies only the direct treatment of the fuel gas using LO-CAT®, THIOPAQ®, or H_2S scavengers as being feasible technologies for removing H_2S from the fuel gas. Therefore, the economic, energy, and environmental impacts of these specific control technologies are addressed below to arrive at the final level of control that represents BACT.

C3.4.1 Liquid Redox (LO-CAT®)

The LO-CAT® system is composed of an absorber tower, oxidizer vessel, and pressure filter package. A LO-CAT® system can reduce H_2S levels in the produced gas by 99 percent or approximately 89.6 tpy of SO_2 (from 90.5 tpy[1] to 0.9 tpy). The cost of the LO-CAT® system is based on equipment sizing and costs provided by Merichem (Merichem 2020).

C3.4.1.1 Cost Estimate Basis

The sulfur to be treated as part of the Grayling Platform project is estimated to be approximately 248 lb S/day based on treatment of 2.1 MMscfd of produced gas with an H_2S concentration of 1,400 ppmv. Since the size and cost estimate provided by Merichem was based on a higher gas rate (6.6 MMscfd), the revised capital cost for a LO-CAT® system on the Grayling Platform was adjusted using the six-tenths rule. (The six-tenths rule is an industry standard method of

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[1] See Section C2 for calculation.

estimating costs of similar equipment of different sizes as suggested by the Department of Energy. More information is provided in **Appendix C** to this section of the application.)

C3.4.1.2 Economic Impacts

The total capital cost to install a LO-CAT® system capable of treating 2.1 MMscfd of produced gas with an H_2S concentration of 1,400 ppmv is approximately $10.2 million, as shown in **Table C3-4**. Direct capital costs include costs for equipment and construction. Equipment costs include the LO-CAT® package, initial chemical charge, pressure filter package for handling sulfur, and chemical injection package to support the LO-CAT® treatment system. The module would be shipped to the OSK dock in Nikiski, Alaska, and loaded onto a barge for transport to the Grayling Platform. Construction costs include integrating the module into the existing fuel gas system.

Indirect capital costs associated with construction include engineering and procurement, UOC, and a technology licensing fee for LO-CAT®. Items included in the UOC are Hilcorp's project team, operations and maintenance personnel, safe-out, work permits, construction coordination and support, and start-up.

Total annualized costs, shown in **Table C3-5**, are approximately $2.04 million for treating formation gas. Direct annualized costs include operating and maintenance labor, parts and materials, chemical usage, and cost of utilities. Operating labor is conservatively based on one half-hour per shift or one hour per day to monitor the LO-CAT® and water treatment systems. The annual cost of chemicals is estimated at $31,390. Utilities include potable water to provide make-up for the water lost to the sweetened gas stream in the LO-CAT® absorber and electrical power to drive system pumps and blowers. The estimated potable water usage is 0.45 gallons per minute (gpm). The cost of the potable water is estimated at $3.50 per 1,000 gallons. To avoid accidental contamination during transport of the water, all potable water would be barged to the platform in 5,000-gallon lined IMO tanks. The tank size is specified to limit the weight (~ 42,000 lbs per tank) for easy lifting onto the platform with the cranes. It is estimated that twelve trips will be required annually to provide water for the platform at a cost of $15,000 per trip. The water must then be purified using a reverse osmosis system before being introduced into the LO-CAT® system. Potable water could be treated on shore and barged to the facility, but the injection rates are so low that the cost of an RO system will not impact economics. The cost of purified water would be higher than the costs for potable water, so the annualized costs shown in **Table C3-5** are conservative. The estimated power to drive the pumps and compressors is 62 kilowatts electric (kWe).

Indirect costs include overhead, property taxes, insurance, G&A, and capital recovery, each of which is estimated based on a percentage of the total capital cost (TCC). The capital recovery cost is based on a 10-year equipment life at 4 percent rate of return (ROR).

Total cost effectiveness for LO-CAT® is $22,857 per ton of SO_2 removed per year. This cost is well above any previous determinations by ADEC and is clearly excessive.

C3.4.1.3 Energy Impacts

The LO-CAT® system requires approximately 62 kWe to drive pumps. There are no other known energy impacts.

C3.4.1.4 Environmental Impacts

The LO-CAT® system generates a sulfur waste product that would require transportation back to shore and for disposal in the nearby landfill. LO-CAT® also uses a small amount of caustic solution to control the acidity of the oxidizer vessel content. The frequency of moving chemicals will increase the potential for a spill in the inlet.

C3.4.1.5 Conclusion

The annualized cost of LO-CAT® is approximately $22,857 per ton of SO_2 removed per year. Based on the excessive cost per ton of SO_2 removed per year, installation of a LO-CAT® system is not considered a cost-effective option for reducing SO_2 emissions. If a major design analysis is required for the platform to accommodate the size and weight of the LO-CAT® skid, the cost could escalate significantly.

Table C3-4: Grayling Platform LO-CAT® Capital Costs

Direct Costs	
1) Purchased Equipment Costs	
a) Basic Equipment and Auxiliaries **(A)**	$2,895,866
b) Instrument and Controls [0.10 * (A)]	$289,587
c) Spare Parts [0.02 * (A)]	$57,917
d) Freight [0.10 * (A)]	$289,587
e) Taxes [0.03 * (a + b + c)]	$19,113
Total Purchased Equipment Cost **(B)**	**$3,552,070**
2) Platform Construction Costs	
a) Supports [0.08 * (A)]	$231,669
b) Erection and Handling [0.14 * (A)]	$405,421
c) Instrumentation [0.02 * (A)]	$57,917
d) Electrical [0.04 * (A)]	$115,835
e) Piping [0.02 * (A)]	$57,917
f) Insulation [0.01 * (A)]	$28,959
g) Painting [0.01 * (A)]	$28,959
Total Platform Construction Cost **(C)**	**$926,677**
Total Direct Costs [TDC] (B + C)	**$4,478,747**
Indirect Costs	
3) Engineering and Procurement [0.19 * (A)]	$550,215
4) Unit Operator Costs **(UOC)** [0.13 * TDC]	$582,237
5) Start-up (Included with UOC)	Included with UOC
6) Performance Test [0.015 * (B)]	$53,281
7) License Fee [Vendor Data]	Unknown
Total Indirect Costs (IDC)	**$1,185,733**
Total Direct Costs + Indirect Costs (TDC + IDC)	**$5,664,480**
8) Contingency (30% of TDC + IDC)	**$1,699,344**
9) Retrofit Factor (50% of TDC + IDC)	**$2,832,240**
Total Capital Costs (TCC) [TDC + IDC + Contingency + Retrofit]	**$10,196,064**

Table C3-5: Grayling Platform LO-CAT® Annual Costs

Direct Costs	
1) Operating Labor: 0.5 hr per 12 hr shift (365 hrs/yr @ $96/hr) **(E)**	$35,040
2) Supervisory Labor [0.15 * (E)]	$5,256
3) Maintenance Labor: 0.55 hr per 12 hr shift (402 hrs/yr @ $96/hr)	$38,544
4) Parts and Materials [100 percent of maintenance labor]	$38,544
5) Utilities	
a) Electricity ($0.094/kW-hr, 62 kWe, 8,760 hr/yr)	$51,053
b) Potable Water ($3.50/1000 gal., 0.45 gpm, 8,760 hr/yr)	$828
c) Shipment of Potable Water (12 trips/yr, $15,000/trip)	$180,000
d) RO Replacement Filters ($28, 12 replacement per year)	$336
e) Sulfur Landfill Disposal (409 lbs Sulfur cake/day, 365 days, $45/ton)	$2,037
6) Chemicals ($86/day, 365 days/yr)	$31,390
a) (Included with shipment of potable water)	$0
Total Direct Costs	$383,028
Indirect Costs	
7) Overhead [included in 1) and 3)]	$0
8) Property Tax (0.01 * TCC)	$101,961
9) Insurance (0.01 * TCC)	$101,961
10) G&A Charges (0.02 * TCC)	$203,921
11) Capital Recovery (CRF * TCC)	$1,257,082
[Capital Recovery Factor **(CRF)** (4 percent ROR, 10-year life **= 0.12329**)]	
Total Indirect Costs	$1,664,925
TOTAL ANNUALIZED COSTS	$2,047,953
Tons/year of SO_2 Removed	89.6
COST EFFECTIVENESS ($/ton SO_2 emission reduction)	$22,857

C3.4.2 THIOPAQ® Bio-Desulfurization

C3.4.2.1 Cost Estimate Basis

The THIOPAQ® Bio-Desulfurization Unit is composed of an inlet scrubber, solution contactor, outlet scrubber, bio-reactor tank, blower, chemical storage tanks, water treatment system, and a gas dehydration unit. According to the vendor, Paqell (Paqell 2020), the THIOPAQ® system can reduce the H_2S to a concentration level <25 ppmv. Based on 25 ppmv, the H_2S that would be removed from the fuel gas equates to approximately 88.9 tpy of SO_2 (from 90.5 tpy[2] to 1.6 tpy). Since the size and cost estimate provided by Paqell was based on higher gas rates (6.6 MMscfd), the revised cost for a THIOPAQ® system on the Grayling Platform was adjusted using the six-tenths rule.

C3.4.2.2 Economic Impacts

The total capital cost to install a THIOPAQ® system capable of treating 2.1 MMscfd of produced gas is approximately $7.04 million, as shown in **Table C3-6**. Equipment costs include the THIOPAQ® package, initial chemical charge, pressure filter package for handling sulfur, and chemical injection package to support the THIOPAQ® treatment system. The module would be shipped to the OSK dock in Nikiski, Alaska, and loaded onto a barge for transport to the Grayling Platform. Construction costs include integrating the module into the existing fuel gas system.

Indirect capital costs associated with construction include engineering and procurement, and UOC. Items included in the UOC are Hilcorp's project team, operations and maintenance personnel, safe-out, work permits, construction coordination and support, and start-up.

Total annualized costs, shown in **Table C3-7**, are approximately $1.68 million for treating 2.1 MMscfd of produced gas. Direct costs include operating and maintenance labor, parts and materials, chemical usage, and cost of utilities. Operating labor is conservatively based on one half-hour per shift or one hour per day to monitor THIOPAQ® and dehydration systems. Maintenance labor is based on 110 percent of operating labor. The hourly rate for labor includes overhead charges such as benefits, overtime, transportation costs to and from the platform, and food and lodging while on the platform. The annual cost of chemicals is estimated at $20,075 based on information provided by Paqell (Paqell 2020). Utilities include potable water to provide make-up for the water lost to the sweetened gas stream in the contactor, electrical power to drive system pumps, blowers and the regeneration skid and disposal of the total sulfur. The vendor considered the make-up water and power required as proprietary and did not provide any detailed information. These costs were set to zero.

Indirect capital costs include overhead, property taxes, insurance, G&A, and capital recovery, each of which is based on a percentage of the total capital cost (TCC). The capital recovery factor is based on a 10-year equipment life at 4 percent rate of return (ROR).

Total cost effectiveness for a THIOPAQ® system is $14,516 per ton of SO_2 removed. This cost is well above any previous determinations by ADEC and is clearly excessive.

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[2] See Section C2 for calculation.

C3.4.2.3 Energy Impacts

Although it is anticipated that there will be power requirements for this project, they have not been addressed because the vendor considered the make-up water and power required as proprietary and did not provide any detailed information.

C3.4.2.4 Environmental Impacts

The THIOPAQ® process generates a sulfur waste by-product that would require transport off the platform and disposal in the nearby landfill.

C3.4.2.5 Conclusion

The annualized cost of a THIOPAQ® treatment system is estimated to be $14,516 per ton of SO_2 removed. THIOPAQ® requires a footprint of 50 feet x 50 feet. Without detailed engineering it is unknown if the platform has available space or can support the added weight of the skid. The system is not considered to be cost effective and will not be considered further.

Table C3-6: Grayling Platform THIOPAQ® Capital Costs

Direct Costs	
1) Purchased Equipment Costs	
a) Basic Equipment and Auxiliaries **(A)**	$1,999,572
b) Instrument and Controls [0.10 * (A)]	$199,957
c) Spare Parts [0.02 * (A)]	$39,991
d) Freight [0.10 * (A)]	$199,957
e) Taxes [0.03 * (a + b + c)]	$13,197
Total Purchased Equipment Cost **(B)**	**$2,452,675**
2) Platform Construction Costs	
a) Supports [0.08 * (A)]	$159,966
b) Erection and Handling [0.14 * (A)]	$279,940
c) Instrumentation [0.02 * (A)]	$39,991
d) Electrical [0.04 * (A)]	$79,983
e) Piping [0.02 * (A)]	$39,991
f) Insulation [0.01 * (A)]	$19,996
g) Painting [0.01 * (A)]	$19,996
Total Platform Construction Cost **(C)**	**$639,863**
Total Direct Costs [TDC] (B + C)	**$3,092,538**
Indirect Costs	
3) Engineering and Procurement [0.19 * (A)]	$379,919
4) Unit Operator Costs **(UOC)** [0.13 * TDC]	$402,030
5) Start-up (Included with UOC)	Included with UOC
6) Performance Test [0.015 * (B)]	$36,790
7) License Fee [Vendor Data]	Unknown
Total Indirect Costs (IDC)	**$818,739**
Total Direct Costs + Indirect Costs (TDC + IDC)	**$3,911,276**
8) Contingency (30% of TDC + IDC)	$1,173,383
9) Retrofit Factor (50% of TDC + IDC)	$1,955,638
Total Capital Costs (TCC) [TDC + IDC + Contingency + Retrofit]	**$7,040,297**

Table C3-7: Grayling Platform THIOPAQ® Annual Costs

Direct Costs		
1)	Operating Labor: 0.5 hr per 12 hr shift (365 hrs/yr @ $96/hr) **(E)**	$35,040
2)	Supervisory Labor [0.15 * (E)]	$5,256
3)	Maintenance Labor: 0.55 hr per 12 hr shift (402 hrs/yr @ $96/hr)	$38,544
4)	Parts and Materials [100 percent of maintenance labor]	$38,544
5)	Utilities	
	a) Electricity (0.13/kW-hr, [unknown – not provided] kWe, 8,760 hr/yr)	$0
	b) Potable Water ($3.50/1000 gal., [unknown – not provided] gpm, 8,760 hr/yr)	$0
	c) Shipment of Potable Water ([unknown – not provided] trips/yr, $15,000/trip)	$0
	d) RO Replacement Filters ($28, 12 replacement per year)	$336
	e) Sulfur Landfill Disposal (378 lbs Sulfur cake/day, 365 days, $45/ton)	$3,104
6)	Chemicals ($55/day, 365 days/yr)	$20,075
	a) Shipment of Chemicals (Included with shipment of potable water)	$0
	Total Direct Costs	$140,899
Indirect Costs		
7)	Overhead [included in 1) and 3)]	$0
8)	Property Tax (0.01 * TCC)	$70,403
9)	Insurance (0.01 * TCC)	$70,403
10)	G&A Charges (0.02 * TCC)	$140,806
11)	Capital Recovery (CRF * TCC)	$867,998
	[Capital Recovery Factor **(CRF)** (4 percent ROR, 10-year life **= 0.12329**)]	
	Total Indirect Costs	$1,149,610
	TOTAL ANNUALIZED COSTS	$1,290,516
	Tons/year of SO_2 Removed	88.9
	COST EFFECTIVENESS ($/ton SO_2 emission reduction)	$14,516

C3.4.3 Solid Scavenger

A solid scavenger system can reduce H_2S levels in the produced gas by 99 percent or approximately 89.6 tpy of SO_2 (from 90.5 tpy[3] to 0.9 tpy). The cost of the solid scavenger system is based on equipment sizing and costs provided by the vendor (Hawk Energy 2020).

C3.4.3.1 Cost Estimate Basis

Treatment of the produced gas using SulfaTreat® scavenger will require a single skid, a water injection system, vacuum collection system and potentially heat exchangers to maintain gas temperatures. A SulfaTreat® skid capable of treating 2.1 MMscfd of gas would consist of two vessels operating in a lead-lag configuration, valving, and interconnecting piping. Each vessel would hold approximately 22,300 pounds (lbs) of media capable of absorbing 7,904 lbs of H_2S during a 30-day period. SulfaTreat® requires that gas be saturated prior to entering the vessels. Therefore, a water injection and mixing system must be incorporated into the main supply piping to add approximately 24 gallons of water per million standard cubic feet of gas. To prevent plugging and contamination of the media, water must be treated to remove any impurities prior to injection into the gas. To maintain proper reaction rates within the vessels it may also be necessary to include heat exchangers to raise the gas temperature to 120°F.

C3.4.3.2 Economic Impacts

The total capital cost to install a SulfaTreat® system capable of treating 2.1 MMscfd of produced gas is approximately $1.06 million, as shown in **Table C3-8**. Direct capital costs include costs for equipment and construction. The module would be trucked to the OSK Dock and barged to the platform. Platform construction costs include integrating the skid into the existing fuel gas system. Since the size and cost estimate provided by Hawk Energy was based on higher gas rates (6.6 MMscfd), the revised capital cost for a solid scavenger system on the Grayling Platform was adjusted using the six-tenths rule.

Indirect capital costs associated with construction include engineering and procurement, and UOC. Items included in the UOC are Hilcorp's project team, operations and maintenance personnel, safe-out, work permits, construction coordination and support, and start-up.

Total annualized costs, shown in **Table C3-9**, are approximately $1.1 million for treating 2.1 MMscfd of produced gas at 1,400 ppmv. Direct annualized costs include operating and maintenance labor, parts and materials, chemical usage, and cost of utilities. Operating labor is conservatively based on one half-hour per shift or one hour per day to monitor the SulfaTreat®, water treatment, and gas dehydration system. The annual cost of a solid scavenger system for treating 2.1 MMscfd of gas is $393,107 (Hawk Energy 2020). Annual costs also include labor and equipment to change out the media twelve times per year. Replacement of the media is based on transporting the vessel to shore where the spent media is removed and taken to a landfill for disposal. The fresh vessel is then returned to the platform for reinstallation into the skid. Utilities include distilled water and electrical power to drive the water injection pump. The cost of power for the water injection pump has not been included in the annual costs due to insufficient data availability.

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[3] See Section C2 for calculation.

Indirect costs include overhead, property taxes, insurance, G&A, and capital recovery, each of which is estimated based on a percentage of the total capital cost (TCC). The capital recovery cost is based on a 10-year equipment life at 4 percent rate of return (ROR).

Total cost effectiveness for a solid scavenger system is $12,322 per ton of SO_2 removed per year.

Table C3-8: Grayling Platform SulfaTreat® Capital Costs

Direct Costs	
Purchased Equipment Costs	
Basic Equipment and Auxiliaries **(A)**	$301,798
Instrument and Controls [0.10 * (A)]	$30,180
Spare Parts [0.02 * (A)]	$6,036
Freight [0.10 * (A)]	$30,180
Taxes [0.03 * (a + b + c)]	$1,992
Total Purchased Equipment Cost **(B)**	**$370,185**
Platform Construction Costs	
Supports [0.08 * (A)]	$24,144
Erection and Handling [0.14 * (A)]	$42,252
Instrumentation [0.02 * (A)]	$6,036
Electrical [0.04 * (A)]	$12,072
Piping [0.02 * (A)]	$6,036
Insulation [0.01 * (A)]	$3,018
Painting [0.01 * (A)]	$3,018
Total Platform Construction Cost **(C)**	**$96,575**
Total Direct Costs [TDC] (B + C)	**$466,760**
Indirect Costs	
Engineering and Procurement [0.19 * (A)]	$57,342
Unit Operator Costs **(UOC)** [0.13 * TDC]	$60,679
Start-up (Included with UOC)	Included with UOC
Performance Test [0.015 * (B)]	$5,553
License Fee [Vendor Data]	Unknown
Total Indirect Costs (IDC)	**$123,573**
Total Direct Costs + Indirect Costs (TDC + IDC)	**$590,333**

Direct Costs	
Contingency (30% of TDC + IDC)	**$177,100**
Retrofit Factor (50% of TDC + IDC)	**$295,167**
Total Capital Costs (TCC) [TDC + IDC + Contingency + Retrofit]	**$1,062,600**

Table C3-9: Grayling Platform SulfaTreat® Annual Costs

Direct Costs	
1) Operating Labor: 0.5 hr per 12 hr shift (365 hrs/yr @ $96/hr) **(E)**	$17,520
2) Supervisory Labor [0.15 * (E)]	$2,628
3) Maintenance Labor: 0.55 hr per 12 hr shift (402 hrs/yr @ $96/hr)	$38,544
4) Parts and Materials [100 percent of maintenance labor]	$38,544
5) Utilities	
a) Electricity (0.094/kW-hr, Unknown, 8,760 hr/yr)	$0
b) Potable Water ($3.50/1000 gal., 51 gpd, 365 days/yr)	$65
c) Shipment of Potable Water (1 trip/yr, $15,000/trip)	$15,000
d) RO Replacement Filters ($28, 12 replacements per year)	$336
6) Media (22,285 lbs Media/30 days, $1.47/lb media)	$393,107
a) Media Shipment to Shore (24 trips, $15,000 per trip)	$360,000
b) Labor to remove and replace media from vessel	$58,753
c) Landfill Spent Media (22,285 lbs/30 days, $45/ton)	$6,017
Total Direct Costs	$930,515
Indirect Costs	
9) Overhead [included in 1) and 3)]	$0
10) Property Tax (0.01 * TCC)	$10,626
11) Insurance (0.01 * TCC)	$10,626
12) G&A Charges (0.02 * TCC)	$21,252
13) Capital Recovery (CRF * TCC)	$131,009
[Capital Recovery Factor **(CRF)** (4 percent ROR, 10-year life **= 0.12329**)]	
Total Indirect Costs	$173,513
TOTAL ANNUALIZED COSTS	$1,104,027
Tons/year of SO_2 Removed	89.6
COST EFFECTIVENESS ($/ton SO_2 emission reduction)	$12,322

C3.4.3.3 Energy Impacts

There are no energy impacts associated with the solid scavenger unless the gas to be treated requires heat to raise the dewpoint temperature.

C3.4.3.4 Environmental Impacts

The solid scavenger process generates a solid waste by-product that will require transport off the platform and disposal in the nearby landfill.

C3.4.3.5 Conclusion

The annualized cost of a solid scavenger treatment system is estimated to be $12,322 per ton of SO_2 removed. The system is not considered to be cost effective. An additional consideration is the potential size and weight of the skid. A detailed engineering analysis would be required to determine if there is sufficient space on the platform and whether the weight is compatible with the platform load distribution.

C3.4.4 Liquid Scavenger

Treatment of the produced gas using a liquid scavenger is the simplest of the control technologies to implement. The scavenger is injected directly into a contact vessel with the fuel gas. A liquid scavenger system can reduce H_2S levels in the produced gas by 99 percent or approximately 89.6 tpy of SO_2 (from 90.5 tpy[4] to 0.9 tpy).

C3.4.4.1 Cost Estimate Basis

There are no capital costs associated with using a liquid scavenger. There is an existing system on the platform for using liquid scavenger. The system is capable of handling 2.1 MMscfd of produced gas at 1,400 ppmv.

C3.4.4.2 Economic Impacts

Total annualized costs, shown in **Table C3-10**, are approximately $0.999 million for treating 2.1 MMscfd of produced gas. Direct annualized costs include operating and maintenance labor, parts and materials, chemical usage, and cost of utilities. The annual cost of scavenger at this rate is $855,195 (Hilcorp 2020).

Total cost effectiveness for a liquid scavenger is $11,130 per ton of SO_2 removed per year.

C3.4.4.3 Energy Impacts

There is a 30 kWe power requirement to drive the liquid scavenger injection pump.

C3.4.4.4 Environmental Impacts

There are no environmental impacts associated with the use of a liquid scavenger. The residue that results from the sweetening of the gas is injected back into the process.

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[4] See Section C2 for calculation.

C3.4.4.5 Conclusion

The annualized cost of a liquid scavenger treatment system is estimated to be $11,130 per ton of SO_2 removed. Use of a liquid scavenger is not considered to be cost effective.

Table C3-10: Grayling Platform Liquid Scavenger Annual Costs

Direct Costs		
1)	Operating Labor: 0.5 hr per 12 hr shift (365 hrs/yr @ 96/hr) **(E)**	$35,040
2)	Supervisory Labor [0.15 * (E)]	$5,256
3)	Maintenance Labor: 0.55 hr per 12 hr shift (402 hrs/yr @ $96/hr)	$38,544
4)	Parts and Materials [100 percent of maintenance labor]	$38,544
5)	Utilities	
	a) Electricity ($0.094/kW-hr, 30 kWe, 8,760 hr/yr)	$24,703
6)	Liquid Scavenger: ($7.81/gal, 300 gal/day,365 days)	$855,195
	Total Direct Costs	$997,282
	TOTAL ANNUALIZED COSTS	$997,282
	Tons/year of SO_2 Removed	89.6
	COST EFFECTIVENESS ($/ton SO_2 emission reduction)	$11,130

C3.4.5 Summary and Conclusions

BACT has been evaluated for potential methods to reduce SO_2 emissions associated with the Grayling Platform. Fuel gas treatment rather than add-on flue gas controls was determined to be the most efficient means of controlling SO_2 emissions. Technologies evaluated include the LO-CAT® redox system, THIOPAQ® Bio-Desulfurization technology, and scavenger products. The cost effectiveness of each option is listed in **Table C3-11**. None of the technologies are found to be cost effective. Therefore, BACT for SO_2 control is good combustion practices.

Table C3-11: Grayling Platform SO_2 Cost Effectiveness Summary

LO-CAT	$22,857
THIOPAQ® Bio-Desulfurization	$14,516
Solid Scavenger	$12,322
Liquid Scavenger	$11,130

C4. References

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Appendix A RACT/ BACT/ LAER

Grayling Platform

Fuel Gas H_2S Increase Project
Construction Permit Application
Attachment C – SO_2 Best Available Control Technology Review

Hilcorp Alaska, LLC

SLR Project No.: 105.00874.20026

October 2023

RACT/BACT/LAER
Boilers of 100 MMBtu/hr or Less

RBLCID	FACILITY_NAME	PERMIT_NUM	PERMIT_ISSUANCE_DATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGHPUT		POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
AR-0138	NUCOR CORPORATION - NUCOR STEEL,	1139-AOP-R14	2/17/2012	VTD BOILER	13.31	NATURAL GAS	50.4	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION	0.1	LB/H
AR-0140	BIG RIVER STEEL LLC	2305-AOP-R0	9/18/2013	BOILER, PICKLE LINE	13.31	NATURAL GAS	67	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION	5.88	X10^-4 LB/MMBTU
AR-0140	BIG RIVER STEEL LLC	2305-AOP-R0	9/18/2013	BOILERS SN-26 AND 27, GALVANIZING LINE	13.31	NATURAL GAS	24.5	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION	5.88	X10^-4 LB/MMBTU
AR-0140	BIG RIVER STEEL LLC	2305-AOP-R0	9/18/2013	FURNACES SN-40 AND SN-42, DECARBURIZING LINE	13.31	NATURAL GAS	22	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION	5.88	X10^-4 LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	2305-AOP-R4	4/5/2019	BOILER, PICKLE LINE	13.31	NATURAL GAS	0		Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION	0.0006	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	2305-AOP-R4	4/5/2019	PREHEATERS, GALVANIZING LINE SN-28 and SN-29	13.31	NATURAL GAS	0		Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION	0.0006	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	2305-AOP-R4	4/5/2019	BOILER, ANNEALING PICKLE LINE	13.31	NATURAL GAS	0		Sulfur Dioxide (SO2)	Combustion of Natural gas and Good Combustion	0.0006	LB/MMBTU
*AR-0159	BIG RIVER STEEL LLC	2305-AOP-R4	4/5/2019	BOILERS SN-26 AND SN-27, GALVANIZING LINE	13.31	NATURAL GAS	0		Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION	0.0006	LB/MMBTU
FL-0335	SUWANNEE MILL	1210468-001-AC(PSD-FL-417)	9/5/2012	Four(4) Natural Gas Boilers - 46	13.31	NATURAL GAS	46	MMBTU/H	Sulfur Dioxide (SO2)	Good Combustion Practice	2	GR OF S/100 SCF
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	0930117-001-AC	3/9/2016	Auxiliary Boiler, 99.8 MMBtu/hr	13.31	NATURAL GAS	99.8	MMBtu/hr	Sulfur Dioxide (SO2)	Use of low-sulfur gas	2	GR. S/100 SCF GAS
FL-0356	OKEECHOBEE CLEAN ENERGY CENTER	0930117-001-AC	3/9/2016	Two natural gas heaters	13.31	NATURAL GAS	10	MMBtu/hr	Sulfur Dioxide (SO2)	Use of low-sulfur fuel	2	GR. S/100 SCF GAS
*FL-0363	DANIA BEACH ENERGY CENTER	0110037-017-AC	12/4/2017	Two natural gas heaters	13.31	NATURAL GAS	9.9	MMBtu/hr	Sulfur Dioxide (SO2)	Clean fuel	2	GRAINS S / 100 SCF
*FL-0363	DANIA BEACH ENERGY CENTER	0110037-017-AC	12/4/2017	99.8 MMBtu/hr auxiliary boiler	13.31	NATURAL GAS	99.8	MMBtu/hr	Sulfur Dioxide (SO2)	Clean fuels	0	
*FL-0367	SHADY HILLS COMBINED CYCLE	1010524-001-AC	7/27/2018	60 MMBtu/hour Auxiliary Boiler	13.31	NATURAL GAS	60	MMBtu/hour	Sulfur Dioxide (SO2)	Limited sulfur content in natural	0	
IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	141-31003-00579	12/3/2012	TWO (2) NATURAL GAS AUXILIARY BOILERS	13.31	NATURAL GAS	80	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPECIFICATIONS	0.0022	LB/MMBTU
LA-0246	ST. CHARLES REFINERY	PSD-LA-619(M6)	12/31/2010	EQT0323 - Boiler 401F	13.31	NATURAL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)	Natural gas or Refinery Fuel Gas with H2S <=100 ppv	2.54	LB/H
LA-0305	LAKE CHARLES METHANOL FACILITY	PSD-LA-803(M1)	6/30/2016	Gasifier Start-up Preheat Burners	13.31	NATURAL GAS	23	MM BTU/hr (each)	Sulfur Dioxide (SO2)	good engineering practices, good combustion technology, and use	0	
LA-0305	LAKE CHARLES METHANOL FACILITY	PSD-LA-803(M1)	6/30/2016	WSA Preheat Burners	13.31	NATURAL GAS	0		Sulfur Dioxide (SO2)	good engineering design and practices and use of clean	0	

RACT/BACT/LAER
Boilers of 100 MMBtu/hr or Less

RBLCID	FACILITY_NAME	PERMIT_NUM	PERMIT_ISSUANCE_DATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGHPUT		POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
*LA-0349	DRIFTWOOD LNG FACILITY	PSD-LA-824	7/10/2018	Hot Oil Heaters (5)	13.31	NATURAL GAS	16.13	mm btu/hr	Sulfur Dioxide (SO2)	Good Combustion Practices and Use of low sulfur facility	0	
MA-0039	SALEM HARBOR STATION	NE-12-022	1/30/2014	Auxiliary Boiler	13.31	NATURAL GAS	80	MMBTU/H	Sulfur Dioxide (SO2)		0.9	PPMVD@3% O2
*MD-0042	WILDCAT POINT GENERATION FACILITY	CPCN CASE NO. 9327	4/8/2014	AUXILLARY BOILER	13.31	NATURAL GAS	45	MMBTU/H	Sulfur Dioxide (SO2)	EXCLUSIVE USE OF PIPELINE QUALITY	0.0006	LB/MMBTU
MI-0423	INDECK NILES, LLC	75-16	1/4/2017	FGFUELHTR (Two fuel pre-heaters identified as EUFUELHTR1 & EUFUELHTR2)	13.31	NATURAL GAS	27	MMBTU/H	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline quality natural gas.	2000	GR/MMSCF
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	6/29/2018	EUAUXBOILER (North Plant): Auxiliary Boilder	13.31	NATURAL GAS	61.5	MMBTU/H	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline	1.8	LB/MMSCF
MI-0433	MEC NORTH, LLC AND MEC SOUTH LLC	167-17 AND 168-17	6/29/2018	EUAUXBOILER (South Plant): Auxiliary Boiler	13.31	NATURAL GAS	61.5	MMBTU/h	Sulfur Dioxide (SO2)	Good combustion practices and the use of pipeline	1.8	LB/MMSCF
NJ-0079	WOODBRIDGE ENERGY CENTER	18940 - BOP110003	7/25/2012	Commercial/Institutional size boilers less than 100 MMBtu/hr	13.31	NATURAL GAS	2000	hours/year	Sulfur Dioxide (SO2)	Use of natural gas	0.162	LB/H
NJ-0080	HESS NEWARK ENERGY CENTER	08857/BOP110001	11/1/2012	Boiler less than 100 MMBtu/hr	13.31	NATURAL GAS	51.9	mmcubic ft/year	Sulfur Dioxide (SO2)	use of natural gas a clean fuel and a low	0.08	LB/H
NJ-0084	PSEG FOSSIL LLC SEWAREN	18068/BOP150001	3/10/2016	Auxiliary Boiler firing natural gas	13.31	NATURAL GAS	687	MMCFT/YR	Sulfur Dioxide (SO2)	Use of natural gas a low sulfur fuel	0.12	LB/H
NJ-0085	MIDDLESEX ENERGY CENTER, LLC	19149/PCP150001	7/19/2016	AUXILIARY BOILER	13.31	NATURAL GAS	4000	H/YR	Sulfur Dioxide (SO2)	USE OF NATURAL GAS A CLEAN BURNING LOW	0.128	LB/H
NY-0104	CPV VALLEY ENERGY CENTER	3-335600136/00001	8/1/2013	Auxiliary boiler	13.31	NATURAL GAS	0		Sulfur Dioxide (SO2)	Natural gas.	0.0022	LB/MMBTU
OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	P0112127	5/7/2013	4 Indirect-Fired Air Preheaters	13.31	NATURAL GAS	0		Sulfur Dioxide (SO2)		0.001	LB/MMBTU
OH-0367	SOUTH FIELD ENERGY LLC	P0119495	9/23/2016	Auxiliary Boiler (B001)	13.31	NATURAL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)	natural gas/ultra low sulfur diesel	0.15	LB/H
OH-0370	TRUMBULL ENERGY	P0122331	9/7/2017	Auxiliary Boiler (B001)	13.31	NATURAL GAS	37.8	MMBTU/H	Sulfur Dioxide (SO2)	Low sulfur fuel	0.06	LB/H
OH-0372	OREGON ENERGY	P0121049	9/27/2017	Auxiliary Boiler (B001)	13.31	NATURAL GAS	37.8	MMBTU/H	Sulfur Dioxide (SO2)	low sulfur fuel	0.06	LB/H
OH-0374	GUERNSEY POWER STATION LLC	P0122594	10/23/2017	Fuel Gas Heaters (2 identical, P007 and	13.31	NATURAL GAS	15	MMBTU/H	Sulfur Dioxide (SO2)	Pipeline natural gas fuel	0.023	LB/H
OH-0377	HARRISON POWER	P0122266	4/19/2018	Auxiliary Boiler (B001)	13.31	NATURAL GAS	44.55	MMBTU/H	Sulfur Dioxide (SO2)	Pipeline quality	0.022	LB/H
OH-0377	HARRISON POWER	P0122266	4/19/2018	Auxiliary Boiler (B002)	13.31	NATURAL GAS	80	MMBTU/H	Sulfur Dioxide (SO2)	Pipeline quality	0.12	LB/H
*OH-0381	NORTHSTAR BLUESCOPE STEEL, LLC	P0126431	9/27/2019	Tunnel Furnace #2 (P018)	13.31	NATURAL GAS	88	MMBTU/H	Sulfur Dioxide (SO2)	Use of natural gas, good combustion practices and design	0.05	LB/H
SC-0113	PYRAMAX CERAMICS, LLC	0160-0023	2/8/2012	BOILERS	13.31	NATURAL GAS	5	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND	0	
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD	118901, GHGPSDTX108 AND PSDTX1	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	13.31	NATURAL GAS	40	MMBTU/H	Sulfur Dioxide (SO2)	Good combustion practice to ensure complete	5	GR/100 SCF

RACT/BACT/LAER
Boilers of 100 MMBtu/hr or Less

RBLCID	FACILITY_NAME	PERMIT_NUM	PERMIT_ISSUANCE_DATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGHPUT		POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD	118901, GHGPSDTX108 AND PSDTX1	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	13.31	NATURAL GAS	95.7	MMBTU/H	Sulfur Dioxide (SO2)	Fuel total sulfur content will be less than or equal to 5	5	GR/100 SCF
TX-0772	PORT OF BEAUMONT PETROLEUM TRANSLOAD	118901, GHGPSDTX108 AND PSDTX1	11/6/2015	Commercial/Institutional-Size Boilers/Furnaces	13.31	NATURAL GAS	13.2	MMBTU/H	Sulfur Dioxide (SO2)	Good combustion practice to ensure complete	5	GR/100 SCF
TX-0845	ARKEMA BEAUMONT PLANT	865A, PSDTX1016M2, GHGPSDTX168	8/24/2018	HEATERS	13.31	NATURAL GAS	31	BTU/HR	Sulfur Dioxide (SO2)	low sulfur fuel and minimization of sulfur in waste through good	5	GR/100 DSCF
*TX-0888	ORANGE POLYETHYLENE PLANT	155952 PSDTX1556 GHGPSDTX192	4/23/2020	Heaters	13.31	NATURAL GAS	100	MMBtu	Sulfur Dioxide (SO2)	Good combustion practice, clean fuel, and proper design	2	GR/100 SCF
VA-0321	BRUNSWICK COUNTY POWER STATION	52404	3/12/2013	AUXILIARY BOILER	13.31	NATURAL GAS	66.7	MMBTU/H	Sulfur Dioxide (SO2)	Low sulfur fuel.	0.0011	LB/MMBTU
*WI-0283	AFE, INC. â€“LCM PLANT	17-JJW-207	4/24/2018	B01-B12, Boilers	13.31	NATURAL GAS	28	mmBTU/hr	Sulfur Dioxide (SO2)	Good Combustion Practices and the Use of Pipeline	0.0006	LB/MMBTU
*WI-0284	SIO INTERNATIONAL WISCONSIN, INC. - ENERGY PLANT	18-JJW-017	4/24/2018	B13-B24 & B25-B36 Natural Gas-Fired Boilers	13.31	NATURAL GAS	28	mmBTU	Sulfur Dioxide (SO2)	Good Combustion Practices and The Use of Pipeline	0.0006	LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	2035-AOP-R2	11/7/2018	BOILER, PICKLE LINE	13.31	NATURAL GAS	53.7	MMBTU/HR	Sulfur Oxides (SOx)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION	5.88	X10^-4 LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	2035-AOP-R2	11/7/2018	BOILER SN-26, GALVANIZING LINE	13.31	NATURAL GAS	53.7	MMBTU/HR	Sulfur Oxides (SOx)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION	5.88	X10^-4 LB/MMBTU
AR-0155	BIG RIVER STEEL LLC	2035-AOP-R2	11/7/2018	PREHEATER, GALVANIZING LINE SN-28	13.31	NATURAL GAS	78.2	MMBTU/HR	Sulfur Oxides (SOx)	COMBUSTION OF NATURAL GAS AND GOOD COMBUSTION	5.88	X10^-4 LB/MMBTU
OH-0350	REPUBLIC STEEL	P0109191	7/18/2012	Steam Boiler	13.31	NATURAL GAS	65	MMBtu/H	Sulfur Oxides (SOx)		0.037	LB/H
PA-0291	HICKORY RUN ENERGY STATION	37-337A	4/23/2013	AUXILIARY BOILER	13.31	NATURAL GAS	40	MMBTU/H	Sulfur Oxides (SOx)		0.0021	LB/MMBTU
PA-0296	BERKS HOLLOW ENERGY ASSOC	06-05150A	12/17/2013	Auxiliary Boiler	13.31	NATURAL GAS	40	MMBTU/H	Sulfur Oxides (SOx)		0.19	T/YR
*AR-0162	ENERGY SECURITY PARTNERS GTL PLANT	2409-AOP-R0	1/10/2020	HPU Steam Reformer	13.39	Fuelgas	95.93	MMBtu/hr	Sulfur Dioxide (SO2)	Low sulfur content fuel gas	0.0006	LB/MMBTU
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	PSD-LA-778	5/23/2014	Process Heater (EQT 702)	13.39	Process Gas	73.8	MMBTU/H	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content of no more than 0.005 gr/scf (annual	4.61	LB/HR
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	PSD-LA-778	5/23/2014	Base Oils DW Reactor Feed Heater (EQT 776)	13.39	Process Gas	31	MMBTU/H	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content of no more than 0.005 gr/scf (annual	2.09	LB/HR
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	PSD-LA-778	5/23/2014	Base Oils Light Vacuum Feed Heater (EQT 777)	13.39	Process Gas	71.2	MMBTU/H	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content of no more than 0.005 gr/scf (annual	4.45	LB/HR

RACT/BACT/LAER
Boilers of 100 MMBtu/hr or Less

RBLCID	FACILITY_NAME	PERMIT_NUM	PERMIT_ISSUANCE_DATE	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGHPUT		POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	PSD-LA-778	5/23/2014	Base Oils Heavy Vacuum Feed Heater (EQT 778)	13.39	Process Gas	10	MM BTU/H	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content of no more than 0.005 gr/scf (annual	0.86	LB/HR
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	PSD-LA-778	5/23/2014	HC Reactor Feed Heaters (EQT 736 & 754)	13.39	Process Gas	70.8	MMBTU/H	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content of no more than 0.005 gr/scf (annual	4.43	LB/HR
LA-0291	LAKE CHARLES CHEMICAL COMPLEX GTL UNIT	PSD-LA-778	5/23/2014	DW Reactor Feed Heaters (EQT 738 & 775)	13.39	Process Gas	56.8	MMBTU/H	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content of no more than 0.005 gr/scf (annual	3.61	LB/HR
LA-0298	LAKE CHARLES CHEMICAL COMPLEX GUERBET ALCOHOLS UNIT	PSD-LA-779	5/23/2014	Hot Oil Heater (EQT 772)	13.39	Process Gas	40	MM Btu/hr	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content of no more than 0.005 grains per standard cubic foot	2.33	LB/HR
LA-0302	LAKE CHARLES CHEMICAL COMPLEX EO/MEG UNIT	PSD-LA-779	5/23/2014	Process Heat Boilers B-910A & B-910B (EQTs 1008 & 1009)	13.39	Process Gas	78	MM BTU/HR	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content of no more than 0.005 grains per standard cubic foot	4.6	LB/HR
LA-0303	LAKE CHARLES CHEMICAL COMPLEX ZIEGLER ALCOHOL UNIT	PSD-LA-779	5/23/2014	Reactor Feed Heater (EQT 1160)	13.39	Process Gas	18	MM BTU/HR	Sulfur Dioxide (SO2)	Use of gaseous fuels with a sulfur content of no more than 0.005 grains per standard cubic foot	1.06	LB/HR
*LA-0356	GARYVILLE REFINERY	PSD-LA-822(M2)	9/27/2019	LSR Hydrotreater Stripper Reboiler (101-85, EQT0169)	13.39	Refinery Fuel Gas	25.29	mm btu/hr	Sulfur Dioxide (SO2)	Use refinery fuel gas that meets requirements of 40	0	
TX-0832	EXXONMOBIL BEAUMONT REFINERY	PSDTX768M1, PSDTX799, PSDTX802	1/9/2018	F-2001 Kero HDT Charge Heater and F-2002 Kero HDT Stripper Reboiler	13.39	NATL GAS AND REFINERY GAS	85.5	MMBTU/H	Sulfur Dioxide (SO2)	good combustion and the use of low sulfur gaseous fuel	162	PPMVD
TX-0832	EXXONMOBIL BEAUMONT REFINERY	PSDTX768M1, PSDTX799, PSDTX802	1/9/2018	F-3001 Diesel DHDT Charge Heater and F-3002 Diesel DHDT	13.39	NATL AND REFINERY GAS	66.5	MMBTU/H	Sulfur Dioxide (SO2)	good combustion and the use of gaseous fuel	162	PPMVD
WY-0071	SINCLAIR REFINERY	MD-12620	10/15/2012	BSI Heater	13.39	Refinery Fuel Gas	50	MMBTU/H	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0	
WY-0071	SINCLAIR REFINERY	MD-12620	10/15/2012	583 Vacuum Heater	13.39	Refinery Fuel Gas	64.2	MMBTU/H	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0	
WY-0071	SINCLAIR REFINERY	MD-12620	10/15/2012	Naphtha Splitter Heater	13.39	Refinery Fuel Gas	46.3	MMBTU/H	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0	
WY-0071	SINCLAIR REFINERY	MD-12620	10/15/2012	Hydrocracker H5 Heater	13.39	Refinery Fuel Gas	44.9	MMBTU/H	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0	
WY-0071	SINCLAIR REFINERY	MD-12620	10/15/2012	#1 HDS Heater	13.39	Refinery Fuel Gas	33.4	MMBTU/H	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0	

RACT/BACT/LAER
Simple Cycle Combustion Turbines Less than 25 MW

RBLCID	FACILITY_NAME	PERMIT_NUM	PERMIT_ISSUANCE_DAT	PROCESS_NAME	PROCCESS_TYPE	PRIMARY_FUEL	THROUGHPUT		POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	CASE-BY-CASE_BASIS
LA-0331	CALCASIEU PASS LNG PROJECT	PDS-LA-805	9/21/2018	Aeroderivative Simple Cycle Combustion Turbine	16.11	NATURAL GAS	263	MM BTU/h	Sulfur Dioxide (SO2)	Exclusive Combustion of Low Sulfur Fuel	4	PPMV	BACT-PSD
*WI-0283	AFE, INC. â€“LCM PLANT	17-JJW-207	4/24/2018	P90 â€“ Natural Gas-Fired Emergency Generator	16.11	NATURAL GAS	9.51	mmBTU/hr	Sulfur Dioxide (SO2)	Good Combustion Practices and the Use of Pipeline Quality	0.0056	LB/HR	BACT-PSD
AK-0074	ENDICOTT PRODUCTION FACILITY	AQ0181CPT07	7/29/2011	Combustion	16.15	Fuel Gas	8717	hp	Sulfur Dioxide (SO2)	Concentration of hydrogen sulfide in fuel gas shall not	1000	PPMV	BACT-PSD
AK-0074	ENDICOTT PRODUCTION FACILITY	AQ0181CPT07	7/29/2011	Combustion	16.15	Fuel Gas	5400	hp	Sulfur Dioxide (SO2)	Limit hydrogen sulfide in fuel gas to no more than 1000	1000	PPMV	BACT-PSD
AK-0077	NORTHSTAR PRODUCTION FACILITY	AQ0503CPT06	6/26/2012	Combustion of Fuel Gas by Turbines < 25 MW	16.15	Fuel Gas	24	MW	Sulfur Dioxide (SO2)	H2S content of fuel gas shall not exceed 300 ppmv at any time	300	PPMV	BACT-PSD

Appendix B Vendor Data

Grayling Platform

Fuel Gas H_2S Increase Project
Construction Permit Application
Attachment C – SO_2 Best Available Control Technology Review

Hilcorp Alaska, LLC

SLR Project No.: 105.00874.20026

October 2023

LO-CAT®

The Green Solution to Sulfur Recovery

MERICHEM

The LO-CAT process, available exclusively from Merichem, is a patented liquid redox system that uses a proprietary chelated iron solution to convert H_2S to innocuous, elemental sulfur. It does not use any toxic chemicals and does not produce any hazardous waste byproducts. The environmentally safe catalyst is continuously regenerated in the process.

The LO-CAT technology is applicable to all types of gas streams including air, natural gas, CO_2, amine acid gas, biogas, landfill gas, refinery fuel gas, etc. Flexible design allows 100% turndown in gas flow and H_2S concentrations. With over 35 years of continuous improvement, LO-CAT units are very reliable and require minimal operator attention; many licensees report as little as 1.5 man-hours per day and over 99% on stream efficiency.

LO-CAT Total Package

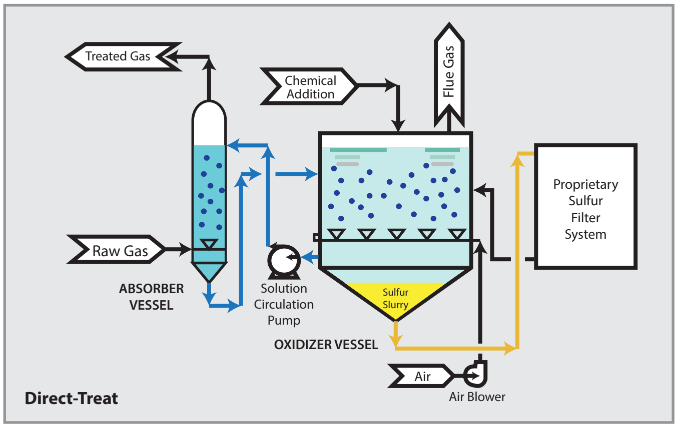
From engineering and fabrication, to installation supervision, training, and startup, through process warranties and onsite service, Merichem provides a total sulfur recovery solution. Each system is custom-designed and built to your specifications and aggressive schedules can be accommodated. Full equipment packages are provided for stick-built or modular configurations.

LO-CAT Direct Treatment Scheme

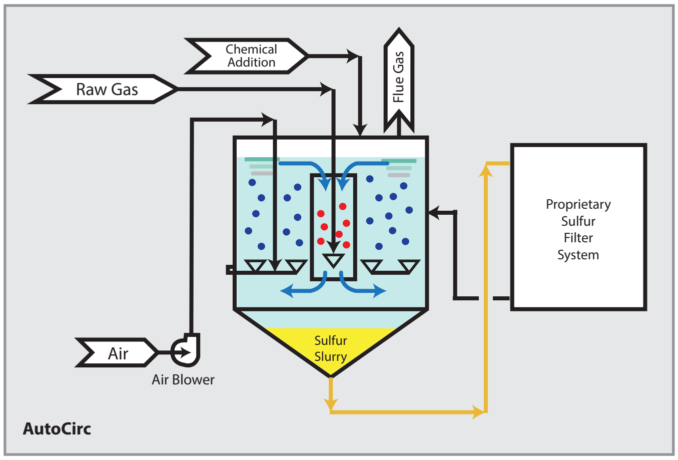
Whenever the treated gas cannot be combined with air, a direct-treat design is employed. This is achieved by use of two separate vessels, an absorber and an oxidizer. The absorber treats the sour gas, producing sweet gas in a single pass. The oxidizer serves two purposes: The regeneration of spent catalyst and the concentration of sulfur particles into a slurry. The proprietary sulfur filter system takes the sulfur-rich slurry, washes it and produces an elemental sulfur cake.

LO-CAT AutoCirc Scheme

When treating a gas that can be mixed with air, the AutoCirc design provides significant cost savings in both operating and capital expenses. By combining the absorber and oxidizer in one vessel, the solution circulation pump is eliminated resulting in reduced electrical consumption. The single vessel approach also minimizes footprint.



Direct-Treat



AutoCirc

Merichem Process Technologies
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Houston, Texas 77023

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Fax: +1 713.921.4604
MPTsales@merichem.com
www.merichem.com

Hilcorp Alaska, LLC
Grayling Platform
LO-CAT Capital Cost Adjustment

Vendor Basis of Estimate

H_2S	1500	ppmv
Gas Rate	6.6	MMscfd
Cost Estimate	$6,000,000	
Sulfur Removed	834.6	lbs/day

Grayling Design

H_2S	1400	ppmv
Gas Rate	2.1	MMscfd
Sulfur Removed	247.8	lbs/day
Sixth-Tenths Rule	0.482644411	
Cost Estimate	$2,895,866	

From: Jeanette Brena <jbrena@slrconsulting.com>
Sent: Thursday, October 22, 2020 7:03 PM
To: Robert Hawley <rhawley@merichem.com>
Cc: Krystin McClure <kmcclure@slrconsulting.com>
Subject: Cost Estimate for LO-CAT® and Amine Treatment

Hello Robert,

I have two facilities that I would like to obtain a cost estimates for – Grayling Platform and Steelhead Platform – for both LO-CAT® and Amine Treatment. Information is provided in the table below and the gas compositions are attached.

	Grayling Platform (1 system)	**Steelhead Platform (1 system)**
H2S Concentration	1500 ppm	4000 ppm
H2S Reduction	Maximum Achievable	Maximum Achievable
Gas Composition	Attached 1 Sample	Attached 2 Samples
Inlet Pressure	50 psi	60 psi
Inlet Temperature	80-130 F	155 F
Wet or Dry Gas?	To be provided	To be provided
Elevation	~ 50 ft	~ 50 ft
Flowrate	6.6 MMscf/d	5.0 MMscf/d
Max SO2 Loading	0.83 tpd	1.68 tpd

Let me know if you have any questions or need any additional information.

Thanks so much!
–Jeanette

SLR

Jeanette Brena, P.E.
Principal Engineer
D 907-264-6974

From: William Echt <wecht@merichem.com>
Sent: October 28, 2020 8:11 AM
To: Jeanette Brena <jbrena@slrconsulting.com>; Krystin McClure <kmcclure@slrconsulting.com>
Cc: Robert Hawley <rhawley@merichem.com>
Subject: FW: Cost Estimate for LO-CAT® and Amine Treatment

Ladies,

Thank you for your interest in Merichem's LO-CAT® technology for H2S removal. I will try to help with your inquiry. Merichem does not offer amine systems.

I am not sure what you mean by Max SO2 Load in the table below. The amount of sulfur in the gas streams are:

Grayling: 6.6 MMSCFD with 1500 ppm H2S contains 0.37 Long Tons Per Day (LTPD) of elemental sulfur (835 lbs/day)
Steelhead: 5.0 MMSCFD with 4000 ppm H2S contains 0.75 Long Tons Per Day of sulfur (1687 lbs/day)

You mention below that you are also looking at amine alternatives. Amine treatment will remove the H2S, but without sulfur recovery you have to burn all the acid gas coming off the amine regenerator. Is the SO2 load the result of this burning of the acid gas?

Merichem can virtually eliminate SO2 emissions by converting the H2S to elemental sulfur. The process would work well by directly treating the associated gas stream, reducing the H2S to <1 ppm. The produced solid sulfur would need to be transported back to shore and disposed of in a landfill.

Merichem typically has an economical application at sulfur loads above 0.5 LTPD. Installation on Grayling would require high CAPEX but would have low OPEX. Installation on Steelhead would be more economical.

I think we should have a conversation to talk about your options. Would you be available tomorrow morning for a call?

Best Regards,

William I. (Bill) Echt
Technology Licensing Director
Merichem Company
5450 Old Spanish Trail
Houston, TX 77023 USA
Cell +1 847.254.9466 (Working from Home)
~~Office +1 847.285.3459~~
Email wecht@merichem.com
www.merichem.com
Sulfur removal from gas and liquid streams

From: William Echt <wecht@merichem.com>
Sent: October 30, 2020 9:08 AM
To: Jeanette Brena <jbrena@slrconsulting.com>
Cc: Robert Hawley <rhawley@merichem.com>; Krystin McClure <kmcclure@slrconsulting.com>
Subject: RE: Preliminary Cost Estimate for LO-CAT® system offshore Alaska

Jeanette, answers embedded below in red....

Have a great weekend,
Bill Echt
wecht@merichem.com
Cell: 847.254.9466

From: Jeanette Brena <jbrena@slrconsulting.com>
Sent: Thursday, October 29, 2020 8:33 PM
To: William Echt <wecht@merichem.com>
Cc: Robert Hawley <rhawley@merichem.com>; Krystin McClure <kmcclure@slrconsulting.com>
Subject: RE: Preliminary Cost Estimate for LO-CAT® system offshore Alaska

Hi William,

Can you clarify – is the capital cost for the LO-CAT equipment is $8 million to $10 million installed? ***[WIE]*** As a ballpark value (+/-40%), full equipment package is $6.0 MM and installed cost on land is $9.1 MM. Installation on a platform depends upon use of a single-lift module versus installation on decks. Merichem does not have good estimates for this.

Also, can you provide responses to the following questions regarding the LO-CAT system:

- Do you have a rough order estimate of the capital cost of all equipment not installed? ***[WIE]*** see above

- Also, you stated on the phone that an iron chemical would be required – do you have estimated on its replacement schedule and cost? Such as replace 1000 pounds of iron every 3 years at a cost of $5/pound. ***[WIE]*** Total chemical consumption is estimated at USD 290/day. This includes caustic purchased by the owner as a commodity and proprietary chemicals supplied by Merichem.

- What are the electrical needs of the system – kW or KW-hr/yr?***[WIE]*** Preliminary estimate is 210 kW.

- What is the life of the system? ***[WIE]*** Designed for 25 years, we have units in service for longer than this.

[WIE] Also, Merichem has installed three LO-CAT® units offshore Gulf of Mexico (all now idle due to lack of gas) and an FPSO. The FPSO operated for 5 years. I have attached my case study. It contains a comparison of OPEX versus scavengers.

Thanks again so very much!
Jeanette

SLR

Jeanette Brena, P.E.
Principal Engineer

D 907-264-6974
O 907-222-1112
C 907-227-5569
E jbrena@slrconsulting.com

SLR International Corporation
2700 Gambell Street, Suite 200, Anchorage, AK 99503

From: William Echt <wecht@merichem.com>
Sent: November 03, 2020 5:41 AM
To: Jeanette Brena <jbrena@slrconsulting.com>
Subject: RE: Preliminary Cost Estimate for LO-CAT® system offshore Alaska

Assume the cake is 60% sulfur and 40% water. That will give you the lbs/day of solids for disposal.

Bill Echt
wecht@merichem.com
Cell: 847.254.9466

From: Jeanette Brena <jbrena@slrconsulting.com>
Sent: Monday, November 2, 2020 9:24 PM
To: William Echt <wecht@merichem.com>
Cc: Robert Hawley <rhawley@merichem.com>; Krystin McClure <kmcclure@slrconsulting.com>
Subject: RE: Preliminary Cost Estimate for LO-CAT® system offshore Alaska

Another quick question Bill – do you know the amount of waste cake produced in a year?

Thanks much!
Jeanette

SLR

Jeanette Brena, P.E.
Principal Engineer

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O 907-222-1112
C 907-227-5569
E jbrena@slrconsulting.com

SLR International Corporation
2700 Gambell Street, Suite 200, Anchorage, AK 99503

From: William Echt <wecht@merichem.com>
Sent: November 03, 2020 7:32 AM
To: Jeanette Brena
Cc: Robert Hawley; Krystin McClure
Subject: RE: Preliminary Cost Estimate for LO-CAT® system offshore Alaska

<1 ppm H2S is achievable, or any value above that.

Bill Echt
wecht@merichem.com
Cell: 847.254.9466

From: Jeanette Brena <jbrena@slrconsulting.com>
Sent: Monday, November 2, 2020 2:23 PM
To: William Echt <wecht@merichem.com>
Cc: Robert Hawley <rhawley@merichem.com>; Krystin McClure <kmcclure@slrconsulting.com>
Subject: Re: Preliminary Cost Estimate for LO-CAT® system offshore Alaska

Hi Bill- thanks for this information. What resulting ppm H2S does LO-Cat achieve? Or percent reduction.

Thanks again!
Jeanette

SLR

Jeanette Brena, P.E.
Principal Engineer

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C 907-227-5569
E jbrena@slrconsulting.com

SLR International Corporation
2700 Gambell Street, Suite 200, Anchorage, AK 99503

From: William Echt <wecht@merichem.com>
Sent: November 10, 2020 6:39 AM
To: Jeanette Brena
Subject: RE: Preliminary Cost Estimate for LO-CAT® system offshore Alaska

Make up water rate is 1.0-1.5 gpm.

Bill Echt
wecht@merichem.com
Cell: 847.254.9466

From: William Echt
Sent: Tuesday, November 10, 2020 7:32 AM
To: 'Jeanette Brena' <jbrena@slrconsulting.com>
Subject: RE: Preliminary Cost Estimate for LO-CAT® system offshore Alaska

Jeanette,

Our water spec is attached. Sea water cannot be used a s the system is almost all stainless steel. The LO-CAT® unit for this application is a direct-treat system as shown in the attached sketch. Here is a process description from an old proposal:

PROCESS DESCRIPTION
LO-CAT® technology is a proprietary, liquid redox process that converts H_2S to solid elemental sulfur at ambient temperature. The process utilizes an aqueous solution of iron, whose performance is enhanced by a proprietary blend of non-toxic chemicals. The H_2S is converted to elemental sulfur according to the following overall reaction:
Direct Oxidation Reaction $H_2S + 1/2\ O_2\ H_2O + S^\circ$ (1)
The above reaction is carried out in separate sections of the process by the following redox reactions:
Absorber $H_2S + 2Fe_{+++}\ S^\circ + 2\ Fe_{++} + 2H_{+}$ (2)
Oxidizer $½\ O_2 + H_2O + 2Fe_{++}\ 2OH_{-} + 2Fe_{+++}$ (3)
The **Absorber** reaction represents the oxidation of H_2S to elemental sulfur and the accompanying reduction of the ferric (active) iron to the ferrous (inactive) state. The **Oxidizer** reaction represents the oxidation of the ferrous iron back to the ferric state.
A simplified flow chart for the proposed LO-CAT unit is attached.
The sour syngas must first pass through an Inlet Knockout Pot where any condensate will be removed prior to entering the LO-CAT unit. The gas will then enter the Liquid Filled Absorber (LFA) where the gas will be contacted counter-currently with a circulating stream of LO-CAT solution. H_2S will be absorbed and converted to elemental sulfur in accordance with Reaction 2 above. The sweet gas leaving the LFA will pass through an Outlet Knockout Pot to remove any liquid carryover from the LFA.
In the Oxidizer, air will be sparged through the solution which will allow the reduced iron to be re-oxidized in accordance with Reaction 3. The exhaust gas stream from the Oxidizer can be directed to atmosphere since it will not contain H_2S and will only be slightly depleted of oxygen.
A portion of the regenerated solution will be recycled through a heater/cooler, which will maintain the solution temperature a few degrees hotter than the inlet sour gas stream. This will prevent condensation from occurring in the unit. Most of the remaining effluent solution stream will be directed back to the LFA.

A small stream of LO-CAT solution will be pumped to a Pressure Belt Filter where it will be concentrated into a 60 wt.% sulfur cake. Although there will be 40 wt.% moisture in the cake it will be dry to the touch. The filtrate will be returned to the unit.

There are four catalysts/chemicals that are injected continuously into the system. The additives consist of an iron-rich catalyst solution, a chelate-rich solution, a surfactant and 45 wt% KOH. A catalyst addition skid equipped with day tanks and addition pumps is included in this estimate.

Regards,
Bill Echt
wecht@merichem.com
Cell: 847.254.9466

From: Jeanette Brena <jbrena@slrconsulting.com>
Sent: Monday, November 9, 2020 7:19 PM
To: William Echt <wecht@merichem.com>
Subject: RE: Preliminary Cost Estimate for LO-CAT® system offshore Alaska

Hi Bill,

Two more questions for you.

What are the water needs for the system – and is it deionized water, potable water, or does seawater work?

Do you have a general description of the capital equipment that are typically part of the system?

Thanks again!
Jeanette

SLR

Jeanette Brena, P.E.
Principal Engineer
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2700 Gambell Street, Suite 200, Anchorage, AK 99503

Hilcorp Alaska, LLC
Grayling Platform
THIOPAQ Capital and Chemical Cost Adjustment

Vendor Basis of Estimate		
H_2S	1500	ppmv
Gas Rate	6.6	MMscfd
Cost Estimate	$4,142,950	
moles H2S/day	26.08	
Sulfur Removed	834.6	lbs/day
Grayling Design		
H_2S	1400	ppmv
Gas Rate	2.1	MMscfd
moles H2S/day	7.74	
Sulfur Removed	247.8	lbs/day
Sixth-Tenths Rule	0.482644411	
Cost Estimate	$1,999,572	
Chemicals		
Vendor Basis of Design	$185.26	per day
Grayling Design	$55.02	per day

Paqell.

SRL international Corporation
Attn: Ms. Jeanette Brena
2700 Gambell Street, Suite 200
AK 99503 Anchorage
Alaska
Tel: +19072646974
Jbrena@srlconsulting.com

Utrecht, 23rd November 2020

Concerns: DJ/2020-11/00003 Thiopaq O&G Grayling.

Dear Jeanette,

Please find attached the requested budget quote associated with the construction of a THIOPAQ O&G unit for your Grayling project.

The Thiopaq O&G unit has been designed to meet a H_2S spec in the treated gas of < 25 ppm. Paqell estimated the Capex and Opex for a Thiopaq O&G unit under the conditions for your project in Alaska as follows:

Sulphur load t/d	guaranteed H2S treated gas ppm	Capex M€	Opex (365 DOS) k€	OPEX Per day €	Manhours cost (per year) k€
0.4	<25	3.5	57	157	24

Further details can be found in our proposal, which is described in the next pages.
This estimate should not be construed as a commercial offer capable of acceptance.

If you need any further support, we are happy to provide as required, please let us know on how you would like to proceed with this opportunity.

Yours sincerely,

Desiree de Haan
Business Manager

Joost Timmerman
Managing Director

General project information

SRL has asked Paqell to provide a proposal for a solution to remove H_2S from a gas for the Grayling project in Alaska. SRL has requested to provide a cost estimate for in total 0.38 ton S/day Thiopaq O&G unit. The following design basis was used:

Feed Gas and Gas composition

project details		
Total sulphur load	0.4	t/day
H2S out	25	ppm
origin feed gas	fuel gas	
treated gas use	fuel gas	
gas composition		
Temperature	oC	35.00
Pressure	bara	4.45
flow	nm3/h	7379
mole percentage		
(total) H2S		0.2
CO2		1.6
O2		0.0
C1		53.9
C2		7.3
C3		9.8
C4		9.5
C5		3.8
C6+		1.5
N2		10.8
H2		0.0
CO		0.0
other		0.0
H2O		1.8
mole ppm		
NH3		0.00
COS		0.00
methyl-SH		0.00
ethyl-SH		0.00
propyl-SH		0.00
DMDS		0.00
benzene		0.00
toluene		0.00
optional		0.00
total (%)		100.00

Consideration for design basis

- SRL has provided a gas with no contaminants. Detail gas analysis needs to be reconfirmed as contaminants could influence the design.

Design

The design is based on less than 25 ppmv H_2S in the treated gas. For the project we have selected the Thiopaq O&G line-up with a set-up of 1 Absorber, 1 Bioreactor and 1 Decanter.

Design memo:

basic equipment		
bioreactor (note 1)		
type	-	aerated tank
number	-	1
diameter / reactor	m	
total height / reactor	m	
wet height	m	
total air flow (wet)	Nm3/hr	
pump tank		
number	-	1
scrubber		
number	-	1
diameter / scrubber	m	
estimated total height	m	
total liquid flow top	m3/hr	
decanter / centrifuge		
number	-	1

Design considerations

1. Feed gas pre-conditioning is required: Cooler, knockout vessel, coalescing filter, heater.

THIOPAQ O&G procurement options

The BDP and detailed engineering and possible construction is done through one of our authorized licensors. The cost of Paqell' s scope is included in the firm quote of the authorized licensor.

The "standard" mandatory Paqell scope of a THIOPAQ O&G unit consists of; Paqell basic design services, license fee, process line-up check, start up support, proprietary items and operations support.

Proprietary items

- Reactor Internal(s)
- Seed Sludge
- Nutrients
- Antifoam agent

Consumables & Utilities

The Thiopaq O&G unit uses the following consumables and utilities

- NaOH (50%)
- Nutrients
- Antifoam agent (occasionally)
- Electricity
- Cooling duty (Cooling is typical done with cooling water)
- Make up water
- Air

Estimation of the operational cost

To estimate the direct operational cost Paqell has used the following unit prices:

	Unit price
NaOH (50%)	€400/1000L (estimate)
Nutrients	€2.349/m3
Electricity	€0,1/kWh (estimate)
Make up water	€ 0,7/m3 (estimate)

The direct operational cost per year are estimated for the Grayling project based on the above unit prices is €157euro/day, c.q. k€ 57 per year based on 365 days on stream.

Excluded are limited manpower support (1 hour per day), lab consumables, air and cooling duty. Cooling is typically done with cooling water. Please note that the consumables will be optimized if the project is in the firm phase and the design is optimized.

Capex investment estimate

Paqell does not build complete Thiopaq O&G plants. EPC work is done by an EPC contractor as selected by the end customer. Therefore, Paqell is not able to give an accurate Capex price, because the price will be depending on the EPC contractor selected. Based upon the information provided, a Capex price estimate of the complete Thiopaq O&G installation (excluding civil works) is EUR 3.5 million +/- 40%.

Plot Size

The estimated plot size for 1 absorber, 1 bioreactor, 1 pump tank and sulphur loading area is 15 m by 15 m. This is excluding the area for chemical storage and dosing pumps.

Delivery time estimate

Taking into account the technical details of the project at hand the estimated delivery time is 14-18 months after order which is mainly depending upon the construction time needed by end customer or its EPC subcontractors. Delivery time for the BDP is 15 weeks after order.

Following Paqell's basic design, a third-party contractor by the choice of the end customer will perform detailed design and organize procurement and construction. If parties are unfamiliar with THIOPAQ O&G (TOG) technology Paqell will provide support to enable execution of the detailed engineering/costing phase. Upon request, Paqell can provide a list of companies familiar with TOG for supply of skid-built TOG units.

Unmanned operation

THIOPAQ O&G sites do not have to be manned permanently. While an exact number is difficult to provide, a few hours each day/every other day is typically sufficient. Unmanned operation for weekends, etc., has been proven. Also: see www.paqell.com/downloads for the Citation case.

A clear advantage is that mainly non-proprietary caustic, electric power and make up water are needed for operation, no other proprietary chemicals except for nutrients for the biomass and antifoam. No external analysis is needed to support the operation. These characteristics make THIOPAQ O&G the best suited technology for more remote/isolated locations.

Unit turndown capabilities

Turndown capabilities of the THIOPAQ O&G depend on the number of reactors used in the design but is at least down to 30% of design at the same efficiency levels. If a certain inefficiency is accepted the turndown is even greater while H_2S removal capability remains intact at below 25 ppmv.

THIOPAQ O&G Process Description (general)

The THIOPAQ O&G Process is an environmentally friendly biological process for H_2S removal from sour gas streams and recovery as elemental sulfur (S). The most unique aspect of the process is that it utilizes a living biocatalyst to oxidize H_2S to elemental S. The biocatalyst belongs to the group of naturally occurring colorless sulfur oxidizing organisms. These are autotrophic organisms, which means that CO_2 is required as their sole carbon source. The Bio-catalyst is fast growing and highly resistant to varying process conditions. The energy needed for growth is obtained from the sulphide oxidation process. These organisms are naturally occurring and are not genetically manipulated or modified.

The THIOPAQ O&G Process has the following performance features:

- Essentially complete H_2S removal and recovery as elemental S.
- Extremely simple process configuration and -control with stable operation.
- Low operating and chemical costs.
- Attractive CAPEX
- Freedom of choice regarding engineering and construction
- Wide and flexible operating range from (at least 30%-100%)
- Short system start-up (within hours) and shut down times.
- Environmentally friendly process based on a naturally occurring biocatalyst.
- Biocatalyst reproduces from itself, no refills needed
- No expensive proprietary chemicals
- Inherently safe operation – no free H_2S exists after the absorber inlet.

The THIOPAQ O&G process can be applied to sour feed gases with H_2S concentrations ranging from 50 ppmv to 100 vol%. Regeneration of the scrubbing solution, rather than its disposal, is a key feature of the THIOPAQ O&G Process. Regeneration of the scrubbing solution is possible because the caustic consumption due to the absorption of H_2S is compensated by the oxidation of H_2S to elemental sulfur and hydroxide.

Sour feed gas enters the bottom of a packed absorber column. H_2S is removed from the sour gas in the absorber by the alkaline THIOPAQ O&G solvent. The treated gas passes through a demister to minimize entrainment of solvent and exits the absorber. The H_2S rich solvent from the bottom of the absorber is routed to the bioreactor. The bioreactor is sparged with air to enable the biocatalyst to convert the dissolved sulfide into elemental sulfur (S), thereby regenerating caustic soda. The elemental sulfur is removed from the bioreactor into a settler.

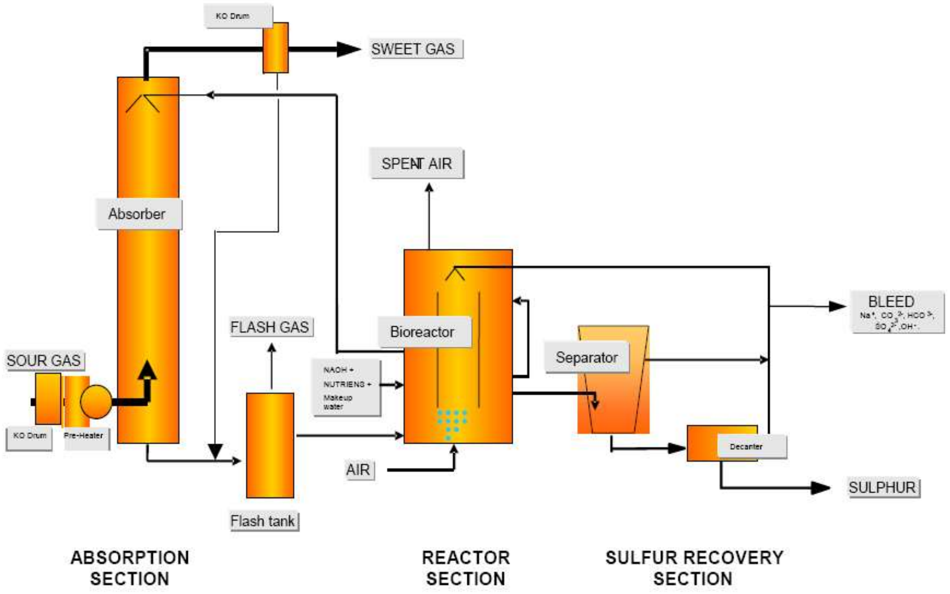

Figure 1: Thiopaq O&G Process

The sulfur slurry is then sent to the sulfur recovery section, where it is further processed in a filter press, with the recovered water recycled back to the process via the bioreactor. The regenerated solvent is recycled from the bioreactor back to the absorber. A small slipstream of solvent is typically bled from the system to prevent any build-up of salts.

The THIOPAQ O&G Process consists, in principle, of three integrated process sections: an absorber, an (an) aerobic biological reactor, and a sulfur separator and/or recovery unit.

Absorber

In the absorber, the sour feed gas is contacted counter-currently with the solvent, which is sprayed downwards through the column by nozzles. From the absorber bottoms, the H_2S rich solvent is routed to the aerobic bioreactor, where the dissolved sulfides are oxidized into elemental S. It is important to note that the elemental S is produced in the bioreactor and not in the absorber. Because of this feature, and the hydrophilic nature of the biologically produced sulfur, plugging problems that frequently occur in conventional caustic or liquid iron-based scrubbing systems are minimized in the THIOPAQ O&G Process. The biologically produced elemental S actually increases the operational reliability of the system and enhances the H_2S absorption.

Bio-reactor

The Aerobic Bioreactors contains microorganisms that oxidize the dissolved sulfides into elemental S. Appropriate bioreactor internals are used to ensure complete mixing. The volume of the bioreactor is designed to achieve optimal activity of the biocatalyst. The exhaust air from the reactor can normally be emitted to the atmosphere without further treatment. The spent air contains less than 1 ppmv H_2S
The air supply to the bioreactor must be controlled to minimize the formation of sulfate and is automated by a control system.

The conversion of H_2S into elemental S is a biological process, and the biocatalysts periodically require nutrients to maintain good performance. The nutrients include certain salts for their growth and maintenance. Extensive laboratory and field research have led to the optimization of the nutrient solution and dosing rate for this process. The nutrient solution is called THEO Powermix 5100 solution and contains up to 12 different salts.

Sulfur Recovery

The produced elemental S is separated from the solvent in a settler. A portion of the bioreactor contents is recycled over the settler to maintain the desired dry solid content in the system. A decanter-centrifuge or filter press is included as a dewatering step after the settler to reach approximately 65% dry matter. The elemental sulfur typically has a purity of ~95-98% on dry basis.

Sulfur applications

The produced sulfur can be used as raw material for agricultural applications as fertilizer or fungicide. Several brands of bio sulfur-based suspension concentrates are marketed. Other options are melting the produced Sulphur to obtain the Claus Sulphur purity specification or landfilling.

Bleed water

This stream is a stream of water with sodiumsalts, biomass and elemental sulfur. PH of this stream is around 8, depending on the location facilities this stream can be send to bleed water treatment of the site, of a separate unit needs to be installed or need to be disposed of.

Please check www.paqell.com for more details on THIOPAQ O&G technology such as an animated process movie and an online quick scan tool for an instant initial feasibility.

Appendix 1. Reference list

THIOPAQ O&G Reference List

A selection of Thiopaq O&G Units

Site	Location	Country	Application	P (barg)	S load (tpd)	H_2S in vol%	Treat H_2S out (ppmv)	Start-up Year
Encana	Bantry	Canada	Natural gas	13.8	0.9	0.2	< 4	2002
XTO Energy I	Teague	USA	Natural gas	79	4	0.175	< 4	2004
XTO Energy II	Fails Eubank	USA	Natural gas	79	4	0.175	< 4	2005
Citation	Salem	USA	Associated gas	4.1	1.5	4	< 4	2006
AMOC	Alexandria	Egypt	Refinery + AG + spent caustic	Ref. gas 4.3; AG 0.5	13	Ref gas 2.5; AG 95	< 10	2007
MPG Pemex	State of Coahuila	Mexico	Acid gas	0.45	11.5	79	< 100	2008
XTO Energy III	Teague	USA	Acid gas	0.65	9.4	9.1	< 50	2008
Chang Chun Petrochem.	Mailao	Taiwan	Refinery	2.3	3.1	41.5	<4	2011
Xinjiang SAD	Xinjiang	China	Coal/AGRU	2.65	13.6	25	<25	2012
CNPC-CKD South West I	Central Sichuan	China	HP natural gas	60	4.5	1	<10	2013
CNPC-CKD South West II	Central Sichuan	China	HP natural gas	60	4.5	1	<10	2013
CNPC-CKD South West III	Central Sichuan	China	HP natural gas	60	4.5	1	<10	2013
CNPC-CKD South West IV	Central Sichuan	China	HP natural gas	60	4.5	1	<10	2014
Pertamina PPGJ	Gundih	Indonesia	NG/AGRU	0.8	15	2.2	<25	2014
Sibur	Tobolsk	Russia	Spend caustic	1	<1	2	<25	2014
Emmen	GZI	NL	Tail gas	0.3	<1		<25	2015
Pertamina Donggi	Sulawesi	Indonesia	NG/AGRU	0.6	14	4	<25	2016
Pertamina Matindok	Sulawesi	Indonesia	NG/AGRU	0.95	12.5	10.5	<25	2017
ENI Zohr	Egypt	Egypt	Acid gas	0.9	5.4	5.7	<25	2018
Santos	Orbost	Australia	NG	28	8	0.3	<4	2020

Projects under Design or Construction

Site	Location	Country	Application	P (barg)	S load (tpd)	H_2S in vol %	H_2S out (ppmv)	Phase
Basrah Gas Company	South-Iraq	Iraq	NG/AGRU	0.5	26	6.5	<25	Engineering Construction phase
Marmul	Oman	Oman	NG	4	1	0,5	< 4	Design phase
Petron	Port Dickson	Malaysia	Refinery gas	9	3.1	2.86	<25	Engineering/ Construction phase
Pernis Refinery	Rotterdam	Netherlands	AGRU	1.8	7.3	5.55	<25	Basic Design Phase
--	--	USA	Refinery gas/SWS off gas	30/1.5	1.2	0.3/19	<4/<25	Basic Design Phase

---

From: Desiree de Haan | Paqell <desiree.dehaan@paqell.com>
Sent: November 24, 2020 8:04 AM
To: Jeanette Brena
Cc: Krystin McClure; Joost Timmerman | Paqell
Subject: RE: Cost Estimate for THIOPAQ
Attachments: Paqell NDA with deed of adherence clause.docx

Goodmorning Jeanette

Please find our answers below in blue
For answers for questions 3-6 and 8 is confidential information. This can be made available by signing a NDA with Paqell
I have attached our NDA

	Steelhead	**Grayling**
H2S	1700 ppm	1500 ppm
Inlet Pressure Gas	60 psi	50 psi
Inlet Temp Gas	155 F	80-130 F
Gas Flowrate	5 MMscf/d	6.6 MMscf/d
S Load	0.415 US Ton/D	0.840 US Tons/D
Capital Cost	5.5 Euros	3.5 Euros
	$6,510,350	$4,142,95
Operating Costs		
NaOH	400 Euros/1000 L	400 Euros/1000 L
	$473.48/1000 L	$473.48/1000 L
Nutrients	2.349 Euros/m3	2.349 Euros/m3
	$2.78/m3	$2.78/m3

1. We are now looking at 1700 ppm H2S for Steelhead – reduced from 4000 ppm H2S. This would be about 0.840 US tons/day S loading. Can you revise any applicable costs?
    a. The Capex investment would be similar to the Grayling
2. For capital costs – can you estimate exclude any install costs from the estimate – so include equipment, instrumentation, auxiliary equipment only? I will be able to better estimate install costs applicable to Alaska.

Paqell can only provide a Capex estimate, this means that civil work is excluded. Below we have listed what is include and what is excluded.

    a. In the Capex estimate is included the following:
        i. Absorber
        ii. Bioreactor
        iii. Decanter centrifuge
        iv. Interconnecting piping with (feed gas) inlet and outlets
        v. Pumps & valves
        vi. Instrumentation
        vii. Control system
        viii. First fill nutrients & seed sludge
        ix. Transport to site
        x. Construction on site and/or skid built in factory

        xi. License Fee
        xii. Engineering cost BDP & detailed engineering
        xiii. Start-up, training & Performance Test Run support
    b. Not included:
        i. Civil works / housing of control room
        ii. Pre-treatment (Knock-out vessel / coalescing filter)
        iii. Piping from upstream installation to Thiopaq O&G installation
        iv. Wastewater treatment (if needed)
3. For operating costs – can you provide the NaOH usage rate, L/day or Gal/day?
4. For operating costs – can you provide the Nutrients usage rate, m3/day or m3/year?
5. For electricity – can you provide the KW demand? I would rather use our local electricity rate for costing.
6. For makeup water – can you provide the usage, L/day or Gal/day? I assume it would need to be fresh water and not seawater?
7. In regards to the Sulfur cake produced – can you provide in lb cake produced/lb S removed or something similar to obtain an annual quantity?
    a. For the Grayling project the sulphur cake produced is 25 kg/hr, please note that the cake contains 35% water, 65 solids
8. In regards to the bleed water – can you provide in L/lb S removed or something similar to obtain an annual quantity?

Kind regards,

Desiree de Haan
Business Manager

T +31 (0)6 1195 8055
E desiree.dehaan@paqell.com
W www.paqell.com

Power of Nature

Hilcorp Alaska, LLC
Grayling Platform
Sulfatreat Capital Cost Adjustment

Vendor Basis of Estimate

H_2S	1500	ppmv
Gas Rate	6.6	MMscfd
Cost Estimate	$625,300	
moles H2S/day	26.08	
Sulfur Removed	834.6	lbs/day

Grayling Design

H_2S	1400	ppmv
Gas Rate	2.1	MMscfd
moles H2S/day	7.74	
Sulfur Removed	247.8	lbs/day
Sixth-Tenths Rule	0.482644411	
Cost Estimate	$301,798	

HAWK ENERGY

15 November 2020

Ref: HE-1111201125-GST

SLR INTERNATIONAL CORPORATION

GRAYLING PLATFORM AND STEELHEAD PLATFORM (ALASKA)

Technical and Commercial Proposal for the Supply of Fuel Gas Desulfurization Unit

TABLE OF CONTENTS

TABLE OF CONTENTS 2

1. EXECUTIVE SUMMARY 3

1.1 ABOUT HAWK ENERGY 3

2. RANGE OF PRODUCTS 4

3. TECHNICAL PROPOSAL 6

3.1 DESIGN BASIS 6
3.2 PROPOSED PROCESS 6
3.3 SYSTEM PERFORMANCE DATA 7
3.4 PERFORMANCE WARRANTY 7
3.5 DIMENSION AND WEIGHT 8

4. COMMERCIAL PROPOSAL 9

4.1 COST OF SUMMARY FOR GRAYLING PLATFORM 9
4.2 COST OF SUMMARY FOR STEELHEAD PLATFORM 9
4.3 EXCLUSIONS 9

5. TERMS & CONDITIONS 10

5.1 TERMS OF PAYMENTS 10
5.2 VALIDITY 10

6. RESPONSIBILITY AND LIABILITY MATRIX 11

1. EXECUTIVE SUMMARY

1.1 About HAWK ENERGY

Established in 2001, we are a knowledge-based business solutions provider making us the ideal partner to professionally service companies within the oil, gas and power sectors. Using the latest in technological advancement in the oil & gas industry, coupled with our highly professional and dedicated staff, we offer solutions from Gas Treatment, Gas Compression to the latest in Offshore/Onshore drilling.

Lead-Lag technology is simple, reliable and well-proven. Each system is designed to address a specific set of process conditions, ensuring an optimized solution for the customer. Predictable performance results are backed by a comprehensive warranty and allow for media change-outs to be planned in accordance with business requirements. During the process the iron-oxide product in the bed chemically reacts with hydrogen sulphide to form a stable and safe by-product.

Lead-Lag configuration technology was considered as the most economical and efficient solution to the problem with a possibility to increase in future. This technology is feasible as the quantities of Hydrogen Sulfide (H_2S) increases and for systems operating with sufficient working pressures. This technology has distinct advantages as compared to other expertise; such as

- Reliable & predictable performance
- Operating flexibility
- Simple vessel change outs
- Low pressure drop
- Straightforward disposal of spent media.

Nearly two decades of experience and technological innovation, Hawk Energy provides the most extensive range of reliable and high-performance products through its principal.

Hawk Energy engineering division offers world class experience in the entire gas processing chain which includes the pre-treatment of the natural gas at the wellhead till the gas is compressed for the suppliers. Hawk Energy offers customized skid mounted systems often referred as “Plug and Play” systems. The beauty of this unit is these can be shifted to new locations after the abandonment of the field. From the desert to the snow, from small to medium to large scale, from standardized to customized builds, our professionals develop engineering solutions that operate reliably and cost-effectively under all conditions.

We empower power through turnkey solutions.

2. RANGE OF PRODUCTS

2.1 Nano LNG-Station - CRYOBOX

When natural gas demand does not justify the investment in a conventional pipeline, Cryobox® is the best complement to Galileo´s Virtual Pipeline, supplying natural gas by highway to mines, remote industries and isolated communities beyond 250 miles. This is possible because the Virtual Pipeline can optimize truck capacity and transport costs owing to LNG properties.

2.2 Gas Conditioning Units- Desulphurization

Hawk Energy has accomplished various projects recommending Fixed Bed (Lead/Lag) Purification Technology which specializes in the removal of Sulphur containments from gas streams and liquids and today is a recognized industry leader in this field.

2.3 Compression Systems for CNG - MICROBOX

Hawk Energy major experience in compression stations is based on being the CNG compression system packages supplier with one of the widest and simplest market lines in the Global Market. They incorporate all the necessary elements to achieve the best performance in terms of easy installation, performance, safety, lay-out and specific consumption. Galileo's product lines, Nanobox, Microbox and Gigabox cover 100% of the CNG market needs.

2.4 Compression System for Natural Gas production and transportation

Hawk Energy has one of the widest product lines for Natural Gas production and transportation of covering from 30 to more than 2000 HP power per unit. Our principle has developed many different package solutions, covering most of the market needs such as: Wellhead compressors, Gathering compressors, Pipeline compressors, Fuel boosters for gas turbines, peak shaving, etc.

2.5 Virtual Pipeline®

Where the distance and demand do not justify the investment in a pipeline, the transport system for CNG offers an attractive alternative for users and gas distributors. By combining the latest technologies in compression and decompression of natural gas, our principle has developed a CNG transport system designed to supply natural gas, by road, to towns, groups of towns, industries and CNG stations.

2.6 CO_2 Removal – Membrane System

CO2 is found in natural gas from many sources. In order to meet pipeline or application specifications the CO2 and other contaminants, e.g.H2O and H2S, must be removed before the methane gas can be used. Hawk Energy offers simple skid mounted plug and play system utilizing Membrane Technology; built as per client requirements.

2.7 Pressure Regulation Plants

Pressure regulating stations are designed and supplied at the end-user station to de-pressurize the Natural Gas and routed at the desired pressure.

2.8 Nitrogen Rejection Units

Hawk Energy is pleased to provide the NRU using proprietary pressure swing adsorption unit with adsorbent design. The market need for N2 removal is well recognized knowing the Nitrogen decreases the heating value of Natural Gas. Typically, all pipeline specifications do not allow for more than 3-4% Nitrogen in the natural gas to avoid transport and storage problems. Therefore, it is paramount to remove Nitrogen from the natural gas streams for the better quality and sales of the gas.

3. TECHNICAL PROPOSAL

3.1 Design Basis

From the information provided by the client in the email dated 22nd October 2020, the process conditions have been defined below:

Parameters	Grayling	Steelhead
Main Feed	Fuel Gas	
Gas Flowrate	6.6 MMSCFD	5.0 MMSCFD
Gas Pressure	50 psig	60 psig
Gas Temperature	80-130 °F	155 °F
Water Saturation	Saturated	Saturated
H2S Concentration	1,500 ppm	4,000 ppm

3.2 Proposed Process

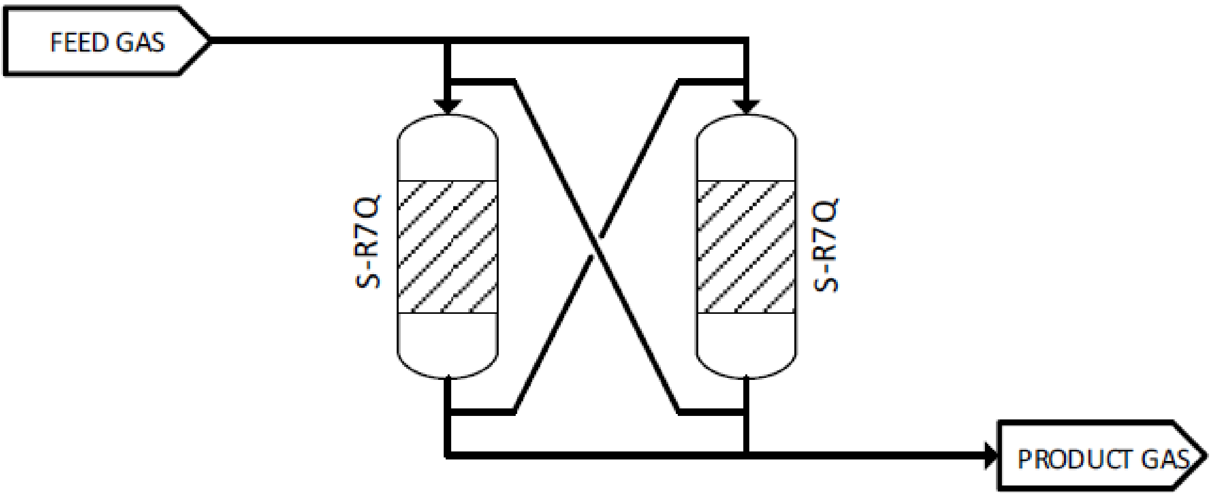

Figure 1: Process Flow Diagram for the Proposed Desulfurization Unit

Figure 1 shows a simplified schematic of the natural gas desulfurization system. The S-R7Q media is housed in two vessels operated in a lead-lag configuration to remove H_2S from the feed stream.

The inexpensive, iron-based, expendable wet-gas media, S-R7Q requires the inlet gas to be saturated, and it also produces one mol of water for every mol of H_2S removed, resulting in a net water production. Please note that the process feed stream dew point will need to be raised or an inlet filter coalescer used upstream to prevent condensation of liquid water in the sorbent beds.

3.3 System Performance Data

Application	**Grayling**	**Steelhead**	**Unit**
Product	**S-R7Q**	**S-R7Q**	
Configuration	Lead/Lag	Lead/Lag	
No. of Vessels	2	2	nos.
Vessel OD	2.75	3.50	m
Vessel T/T	9.22	11.37	m
Total Vessel Loading	**68,096**	**137,568**	**kg**
Outlet Total Sulphur Concentration	**< 1**	**< 1**	**ppm**
Estimated pd (1)	2.5	1.1	psi
Predicted Bed Life (2)	30	30	days

(1) Pressure drop of entire system

(2) Projected bed-life is based on 24hr day operation. Predicted bed-life is per vessel.

3.4 Performance Warranty

Against the process conditions defined, Hawk Energy will warrant that, in the absence of mal operation outside the design operating conditions, the detailed configuration will remove Sulfur from the stated inlet concentration to the defined outlet concentration for not less than stated designed bed life of 12 months, based on operating for no more than twenty-four (24) hours per day from first admission of process gas.

The foregoing warranty shall not apply where failure of the adsorbent is due to its being affected physically or chemically by mal-operation including but not limited to the following incidents;

- multi-phase flow entering the vessel
- improper loading/change outs
- bed collapse
- hydrate formation
- operator error
- solids carried over from other parts of the plant
- catalyst poisons
- faulty construction and/or
- mis-design of items of plant equipment
- Water injection failure

In the event that the absorbent does not meet the warranted performance then Hawk Energy will extend free product credit calculated as follows:

((Warranted days – days in service) / Warranted days) x Vessel Loading

The extent of liability shall be limited to the manufactured cost of the product only, and does not include delivery and any associated costs such as media loading. Should inlet gas parameters change significantly from those stated then any product warranty may be void. As a general rule the most common cause of a short run is either an increased flow rate or an elevated loading of Sulphur component's in the inlet gas stream. Gas contamination by liquid (eg: ineffective filter coalescer/filter separator upstream of the gas treating unit, liquid condensation due to the ambient temperature change impact, etc) or particles may also impact the performance of the media.

** change one of the two vessels and reverse vessel sequence.

3.5 Dimension and Weight

The table below shows the estimated footprint and vessel empty weight of the Desulfurization System. The exact footprint will be determined during the FEED stage.

Platform	Footprint	Vessel Empty Weight
Grayling	5.5 m x 11.0 m	~ 16 MT
Steelhead	7.65 m x 15.25 m	~ 27 MT

4. COMMERCIAL PROPOSAL

4.1 Cost of Summary for Grayling Platform

S. No.	Item Description	Quantity	Amount
1.	**Desulfurization System** • Two (2) media vessels, as described, complete with bed supports and other required internals • Two (2) pressure relief valves, one per vessel	LS	**$ 625,300.00**
2.	**S-R7Q Media Initial Fill**	68,096 kg	**$ 221,312.00**
		TOTAL PRICE, USD	**$ 846,612.00**

4.2 Cost of Summary for Steelhead Platform

S. No.	Item Description	Quantity	Amount
1.	**Desulfurization System** • Two (2) media vessels, as described, complete with bed supports and other required internals • Two (2) pressure relief valves, one per vessel	LS	**$ 785,868.00**
2.	**S-R7Q Media Initial Fill**	137,568 kg	**$ 447,096.00**
		TOTAL PRICE, USD	**$ 1,232,964.00**

4.3 Exclusions

- Feed inlet and product outlet piping
- Manual Process and Purge Valves
- Interconnecting Piping and Valves
- All instrumentation such as pressure gauge and temperature gauge along with Thermowell.
- Gas Sampling System
- Detailed Engineering Design and HAZOP
- Civil Works
- Installation Works
- Any insulation, heat tracing, electrical tracing and Fire-proofing.

5. TERMS & CONDITIONS

Point of Sale:	EXW USA/UAE
Delivery Time:	Media: 26-30 weeks after receipt of order Desulfurization System: 36-40 weeks from date of GA drawing approval
Origin of Goods:	USA/UAE
Packaging:	Industry approved packing

- All prices mentioned in the proposal are in **USD (United States Dollars).**
- The price mentioned above is **EXCLUDING** the freight charges, custom duty or clearance from the Port.
- The price mentioned above is **EXCLUDING** the VAT. 5% VAT will be added if applicable.

5.1 Terms of Payments

- 5% upon Award/Order
- 20% upon approval of GA Drawings
- 30% upon successful completion of Hydrotest for vessels
- 25% upon media shipment
- 10% upon delivery of the vessels on site
- 5% upon installation of the Desulfurization System
- 5% upon commissioning of the Desulfurization System

5.2 Validity

- The validity of this proposal is 30 calendar days from the date of submission.

6. RESPONSIBILITY AND LIABILITY MATRIX

Section	Description	Responsibility of Hawk Energy	Responsibility of Client
1.	**SUPPLY OF MATERIALS**		
	1.1 MEDIA	X	
	1.2 DESULFURIZATION VESSELS	X	
2.	**ENGINEERING**		
	2.1 CONCEPTUAL DESIGN	X	
	2.2 DETAILED ENGINEERING	TBD	
	2.3 VALUE ENGINEERING	TBD	
	2.4 ENGINEERING DESIGN DRAWINGS	TBD	
	2.5 DOCUMENTATION AND SUBMISSION OF REPORTS	TBD	
	2.6 PREPARATION, COMPLETION AND SUBMISSION OF MANUALS & DOSSIERS	TBD	
3.	**HAZOP STUDY**		
	3.1 ARRANGEMENT OF MEETING ROOM		X
	3.2 ARRANGEMENT OF HAZOP CHAIRMAN	TBD	
	3.3 APPROVAL OF HAZOP REPORT	TBD	TBD
	3.4 HAZOP FINAL REPORT	TBD	
4.	**CIVIL WORKS**		
	4.1 CIVIL STRUCTURES AND MATERIALS		X
5.	**SITE WORKS**		
	5.1 SITE PREPARATION		X
6.	**TRANSPORTATION OF MEDIA SUPPLIED BY HAWK ENERGY**		
	6.1 MATERIAL AND SERVICES FOR LOGISTICS		
	Packing and marking of equipment	X	
	Loading of materials/equipment at place of manufacturing	X	
	Transportation of equipment from place of manufacturing to Place of Delivery		X
	Transport insurance from place of manufacturing to Place of Delivery		X
	Unloading of equipment at Place of Delivery		X
	Shifting of equipment to warehouse/open storage/container yard		X
	6.2 MAIN TRANSPORT, SITE TRANSPORT AND UNLOADING OPERATIONS		
	Nomination of vessel or other mean of transport		X
	Engaging and instructing freight forwarder		X
	Arranging of bill of lading		X
	Preparation of origin country documents required for destination customs clearance	X	X
	Transportation of equipment from port of loading to port of destination		X
	Discharging of equipment from vessel or any other transport vehicle at port of destination		X
	Unloading of equipment at warehouse/open storage/container yard at port of destination		X
	Arrange import license or import permit (if required)		X
	Import taxes and other duties (if required)		X
	Transportation of equipment from port of destination to project site		X
	Unloading of equipment at project site		X
7.	**TAXES AND DUTIES**		
	Sales / VAT tax and local taxes		X
	Other taxes / duties (if required)		X

Section	Description	Responsibility of Hawk Energy	Responsibility of Client
8.	PROJECT MANAGEMENT SERVICES		
8.1	PROJECT MANAGEMENT	TBD	
8.2	DOCUMENT CONTROL	TBD	
9.	SITE ADVISORY SERVICES		
9.1	SITE ORGANIZING AND RESOURCING		
	Construction/site management team	TBD	TBD
	Customer site representative	TBD	TBD
	Hawk Energy subcontractors personnel work permits	TBD	TBD
	Assistance and sponsoring for work permit	TBD	TBD
9.2	TRAVEL, ACCOMMODATION AND LOCAL TRANSPORTATION		
	Provision of visa (if required)		X
	Accommodation		X
	Food and local travel	X	
10.	INSTALLATION AND LEAK TEST		
10.1	INSTALLATION SUPPORT OF ALL EQUIPMENT	TBD	
10.2	INSTALLATION OF MECHANICAL EQUIPMENT		X
10.3	INSTALLATION OF INSTRUMENT EQUIPMENT		X
10.4	INSTALLATION OF CIVIL EQUIPMENT		X
10.5	LOADING OF MEDIA		X
10.6	NITROGEN PURGING		X
10.7	LEAK TEST		X
10.8	SUPPORT FOR LOADING, EQUIPMENT TEST	TBD	
10.9	FIELD ASSEMBLY SPECIAL EQUIPMENT REQUIRED		
	Mobile Cranes		X
	Forklift		X
	Loading Hopper		X
	Nitrogen Purging Truck		X
11.	COMMISSIONING		
11.1	INSTALLATION QUALITY ASSURANCE (PRE-COMMISSIONING)	TBD	
11.2	COMMISSIONING	TBD	
11.3	FUNCTIONAL TEST	TBD	
11.4	PERFORMANCE TEST	TBD	
12.	TRAINING	TBD	
13.	UTILITIES (IF REQUIRED)		X

***TBD – To be discussed**

Jeff Alger

From:	Aamir Mehraj <aamir.mehraj@hawkenergy.net>
Sent:	November 15, 2020 2:03 AM
To:	Jeanette Brena
Cc:	'Mshihaby'; jezille.dollosa@hawkenergy.net; irfan@hawkenergy.net
Subject:	Cost Estimate for SulfaTreat
Attachments:	HE-1111201125-GST.pdf

Hello Jeanette Brena,

My name is Aamir Mehraj, I am a Sales Manager with Hawk Energy.

Further to your conversation with Hawk Energy, about the Cost Estimate for SulfaTreat, please find the proposal attached that I would like you to consider.

The proposal includes conceptual design, that meets your requirements, including the estimated weight (approx.) and footprint. We can further modify the design to fulfil your requirements and are happy for any comments and feedbacks regarding the overall design.

I'd appreciate to hear what you think about the proposal. Kindly advise on any changes.

Also, would you be available for a zoom video call this week, to further discuss the said proposal.

Hope to hear from you soon.

Best Regards
Aamir Mehraj
Sales Manager – Oil & Gas

HAWK ENERGY
EMPOWERING POWER

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Location: https://goo.gl/maps/k3kB4arGMUG2

Please consider the environment before printing this e-mail

From: Aamir Mehraj <aamir.mehraj@hawkenergy.net>
Sent: December 06, 2020 6:25 AM
To: Jeanette Brena
Subject: Re: Cost Estimate for SulfaTreat

Hello Jeanette,
Hope you are doing well!
Sorry for the delayed reply as we had public holidays last week. I have answered some of you questions as below:

1. What is the cost per pound to replace the scavenger material? I was guessing about \$4.5 per lb S removed, or would it be a complete refill monthly and if so what is that cost? *The cost of the media is \$3.25/kg (\$ 1.47/lb.). The media refill of each bed is every month, due to the design of the system bearing in mind that this is an offshore platform. For instance in Grayling, the media refill in each vessel is 34,048 kg (≈75,063 lbs.) per month thus the cost of media per monthly refill is ≈ \$ 110,656.00. In addition we have to add the cost to replace the media, where we can sign a long term agreement to provide the services. This design is a lead/lag setup, meaning we can take out the initial lead vessel and replace the media in that vessel onshore and leave the lag vessel in operation.*
2. How often does the changeout in scavenger need to occur? It seemed like the proposal stated it was monthly. *Yes , it is monthly. Furthermore, this being an offshore facility with restricted footprint and weight limit, if you could provide the footprint and weight tolerances, we can optimize the design to enhance and improve the lifespan of the media in the vessel and hence reduce the frequency of the media change out.*
3. Does the system have any electrical requirements, kW? *No electricity requirement. This solution is a stand alone. Neither utilities nor man power is required.*
4. Is there any fresh water needs? *No fresh water requirement. As no. 3*
5. Is disposal of spent material considered inert or hazardous? How much is produced? I was guessing about 10 lb spent material per lb S. *The offered media is Iron-based which is non-hazardous both in fresh and spent form. The spent media can be disposed of in a landfill.*
6. Is the water produced considered fresh/clean water – or does it require storage and disposal? If so, is a holding tank included in the cost? What is the quantity produced? *Produced water will be free of chemical contamination and will be accumulated at the bottom of the vessel. This should be drained from the base of the vessel as a part of regular operator routines. Holding tank is not considered in our proposal. The quantity produced is one mole of water for every mole of H2S removed.*
7. Can you include the cost of the inlet filter coalesce to address dew point? *We will consider this in the revised proposal.*
8. Can you adjust Steelhead costs to 1700 ppm rather than 4000 ppm? *One of the major features of our solution is that it is robust, in other words, regardless of the gas flow rate and the h2s content, we can still treat the gas. The only difference is the expected bedlife in the vessel. From our experience if we reduce from 4000 ppm to 1700 ppm the bed life should increase to 70 days instead of 1 month. kindly confirm the process design data and we will revise our proposal.*
9. Can you include instrumentation in your cost as a separate line item? *Kindly provide your approved vendor list for the instrumentation. Also, kindly advise the line pipe size upstream of our system. Our standard instrumentation is inclusive of temperature gauges, pressure gauges, water level gauges and usually they are not expensive. We can add any other instrumentation such as gas flow meter, gas analyser etc. kindly confirm what are your instrumentation requirements, and we will revise our proposal accordingly.*

Best Regards,
Aamir Mehraj
Sales Manager - Oil & Gas

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Location: https://goo.gl/maps/k3kB4arGMUG2

On Tue, Dec 1, 2020 at 10:28 PM Jeanette Brena <jbrena@slrconsulting.com> wrote:

> Hello,
>
> Thanks for your message, I do have some questions about the proposal:
>
> 1. What is the cost per pound to replace the scavenger material? I was guessing about $4.5 per lb S removed, or would it be a complete refill monthly and if so what is that cost?
> 2. How often does the changeout in scavenger need to occur? It seemed like the proposal stated it was monthly.
> 3. Does the system have any electrical requirements, kW?
> 4. Is there any fresh water needs?
> 5. Is disposal of spent material considered inert or hazardous? How much is produced? I was guessing about 10 lb spent material per lb S.
> 6. Is the water produced considered fresh/clean water – or does it require storage and disposal? If so, is a holding tank included in the cost? What is the quantity produced?
> 7. Can you include the cost of the inlet filter coalesce to address dew point?
> 8. Can you adjust Steelhead costs to 1700 ppm rather than 4000 ppm?
> 9. Can you include instrumentation in your cost as a separate line item?
>
> I appreciate your help!
>
> Jeanette
>
> SLR

Appendix C Support Data

Grayling Platform

Fuel Gas H_2S Increase Project
Construction Permit Application
Attachment C – SO_2 Best Available Control Technology Review

Hilcorp Alaska, LLC

SLR Project No.: 105.00874.20026

October 2023

The Rule of Six-tenths

$$(ratio)^{0.6}$$

Approximate costs can be obtained if the cost of a similar item of different size or capacity is known. A rule of thumb developed over the years known as the *rule of six-tenths* gives very satisfactory results when only an approximate cost within plus or minus 20% is required. An exhaustive search in conjunction with the development of this course left this author with no indication of any single individual who developed this concept. One is forced to assume that the relationship naturally evolved in the public domain after large quantities of actual cost data were analyzed retrospectively. The earliest mention of this concept was found in a reference accredited to a December 1947 *Chemical Engineering* magazine article by Roger Williams, Jr. entitled "Six-tenths Factor Aids in Approximating Costs".

At any rate, the following equation expresses the *rule of six-tenths*:

$$C_B = C_A\left(\frac{S_B}{S_A}\right)^{0.6}$$

Where C_B = the approximate cost ($) of equipment having size S_B (cfm, Hp, ft^2, or whatever)
C_A = is the known cost ($) of equipment having corresponding size S_A (same units as S_B),
and S_B/S_A is the ratio known as the *size factor*, dimensionless.

of Air Quality Planning and Liaison and the U. S. Environmental Protection Agency's Office of Air Planning and Standards.

The cost-effectiveness of an abatement system or strategy is defined as the ratio of the annualized cost of that abatement system over the reduction in annual pollutant emissions achieved by the system for the pollutant in question. Cost-effectiveness can be estimated as follows:

Cost-effectiveness =
(Annualized Cost of Abatement System ($/yr)) / (Reduction in Annual Pollutant Emissions (ton/yr))

The reduction in annual pollutant emissions is the expected decrease in the source's pollutant emissions from its baseline uncontrolled level, achieved by the installation of the abatement system under review. This annual reduction can be calculated as the difference in emissions with and without the abatement system, using District-approved standard emission factors or source test data and the permitted annual usage or throughput limits expected in the operating permit. Simply put,

Reduction in Annual Pollutant Emissions (ton/yr) =
Baseline Uncontrolled Emissions - Control Option Emissions

As noted above, the emissions reductions are calculated using realistic upper boundary operating assumptions (permit limit conditions).

The annualized cost of the abatement system can be estimated from the installed cost of the control and its expected annual operating and maintenance costs.

Annualized cost = Direct Costs + Indirect Costs

where Direct Costs (Sum of the Following):
Labor
Raw Materials
Replacement Parts
Utilities

and Indirect Costs (Sum of the Following):
Overhead (80% of Labor Costs)
Property Tax (1% of Total Capital Cost)
Insurance (1% of Total Capital Cost)
General & Administrative (2% of Total Capital Cost)
Capital Recovery (CRF x Total Capital Cost)

where Total Capital Cost = Installed Equipment Cost

The capital recovery factor (CRF) recognizes the time value of money and converts the up front capital cost (the installed equipment cost) to an annualized cost.

The capital recovery factor (CRF) is given by:

$$\mathbf{CRF} = \frac{\mathbf{i\,(1 + i)^n}}{\mathbf{(1 + i)^n - 1}}$$

where i = interest rate (assume i = 0.06, as determined below)

and n = lifetime of abatement system (assume n = 10 years unless shown to be different).

For example, when i = 0.06 (6 percent interest rate) and n = 10, the capital recovery factor CRF = 0.136.

The current District policy regarding the interest rate (to be used in cost-effectiveness calculations) is similar to the guidelines used by the California Air Resources Board. First, take as a benchmark the interest rate on United States Treasury Securities with a maturity that most closely approximates the project horizon (typically 10 years), add 2 percentage points for incremental risk, and then round the total up to the next higher integer. Use of the 10-Year Treasury Note interest rate (yield) averaged over the previous 6 months will dampen the daily fluctuations of that index. And the addition of two percentage points and rounding up to the next higher integer rate will reflect more closely market conditions while adding further assurance that the project can be financed near or below that final calculated interest rate.

For example, the benchmark average 10-Year Treasury note interest rate for the first six months of 2003 was 3.77%. Adding 2 percentage points and rounding up results in the currently recommended 6% interest rate for cost-effectiveness calculations. This methodology for determining the interest rate can be easily followed; the relevant Treasury note data are readily available from financial publications or the Internet. The interest rates resulting from this methodology are more reflective of market conditions rather than the single fixed number originally used by the *BACT/TBACT Workbook*. Furthermore, use of this interest rate methodology would have generally followed the interest rates used by CARB and U.S. EPA since the initial publication of this *BACT/TBACT Workbook* on June 30, 1995. Looking back, the 10-Year Treasury Note averaged over the first half of 1995 was 7.05%. Had the current District methodology been followed at that time, the calculated interest rate would have been 7.05 + 2.0 = 9.05 → rounded up to 10%, which was exactly the interest rate recommended by the *BACT/TBACT Workbook* at initial publication.

For simple cases of cost-effectiveness determinations where the details of operating and maintenance costs, etc. are not readily available, a rough estimate of cost-effectiveness can be obtained as follows:

Annualized Cost =
Installed Equipment Cost x

10-Year Treasury Rate

Date	Yield
6/3/2019	2.07
6/4/2019	2.12
6/5/2019	2.12
6/6/2019	2.12
6/7/2019	2.09
6/10/2019	2.15
6/11/2019	2.15
6/12/2019	2.13
6/13/2019	2.1
6/14/2019	2.09
6/17/2019	2.09
6/18/2019	2.06
6/19/2019	2.03
6/20/2019	2.01
6/21/2019	2.07
6/24/2019	2.02
6/25/2019	2
6/26/2019	2.05
6/27/2019	2.01
6/28/2019	2
7/1/2019	2.03
7/2/2019	1.98
7/3/2019	1.96
7/5/2019	2.04
7/8/2019	2.05
7/9/2019	2.07
7/10/2019	2.07
7/11/2019	2.13
7/12/2019	2.12
7/15/2019	2.09
7/16/2019	2.13
7/17/2019	2.06
7/18/2019	2.04
7/19/2019	2.05
7/22/2019	2.05
7/23/2019	2.08
7/24/2019	2.05
7/25/2019	2.08
7/26/2019	2.08
7/29/2019	2.06
7/30/2019	2.06
7/31/2019	2.02
8/1/2019	1.9
8/2/2019	1.86
8/5/2019	1.75
8/6/2019	1.73

10-Year Treasury Rate

Date	Yield
8/7/2019	1.71
8/8/2019	1.72
8/9/2019	1.74
8/12/2019	1.65
8/13/2019	1.68
8/14/2019	1.59
8/15/2019	1.52
8/16/2019	1.55
8/19/2019	1.6
8/20/2019	1.55
8/21/2019	1.59
8/22/2019	1.62
8/23/2019	1.52
8/26/2019	1.54
8/27/2019	1.49
8/28/2019	1.47
8/29/2019	1.5
8/30/2019	1.5
9/3/2019	1.47
9/4/2019	1.47
9/5/2019	1.57
9/6/2019	1.55
9/9/2019	1.63
9/10/2019	1.72
9/11/2019	1.75
9/12/2019	1.79
9/13/2019	1.9
9/16/2019	1.84
9/17/2019	1.81
9/18/2019	1.8
9/19/2019	1.79
9/20/2019	1.74
9/23/2019	1.72
9/24/2019	1.64
9/25/2019	1.73
9/26/2019	1.7
9/27/2019	1.69
9/30/2019	1.68
10/1/2019	1.65
10/2/2019	1.6
10/3/2019	1.54
10/4/2019	1.52
10/7/2019	1.56
10/8/2019	1.54
10/9/2019	1.59
10/10/2019	1.67

10-Year Treasury Rate

Date	Yield
10/11/2019	1.76
10/15/2019	1.77
10/16/2019	1.75
10/17/2019	1.76
10/18/2019	1.76
10/21/2019	1.8
10/22/2019	1.78
10/23/2019	1.77
10/24/2019	1.77
10/25/2019	1.8
10/28/2019	1.85
10/29/2019	1.84
10/30/2019	1.78
10/31/2019	1.69
11/1/2019	1.73
11/4/2019	1.79
11/5/2019	1.86
11/6/2019	1.81
11/7/2019	1.92
11/8/2019	1.94
11/12/2019	1.92
11/13/2019	1.88
11/14/2019	1.82
11/15/2019	1.84
11/18/2019	1.81
11/19/2019	1.79
11/20/2019	1.73
11/21/2019	1.77
11/22/2019	1.77
11/25/2019	1.76
11/26/2019	1.74
11/27/2019	1.77
11/29/2019	1.78
12/2/2019	1.83
12/3/2019	1.72
12/4/2019	1.77
12/5/2019	1.8
12/6/2019	1.84
12/9/2019	1.83
12/10/2019	1.85
12/11/2019	1.79
12/12/2019	1.9
12/13/2019	1.82
12/16/2019	1.89
12/17/2019	1.89
12/18/2019	1.92

10-Year Treasury Rate

Date	Yield	
12/19/2019	1.92	
12/20/2019	1.92	
12/23/2019	1.93	
12/24/2019	1.9	
12/26/2019	1.9	
12/27/2019	1.88	
12/30/2019	1.9	
12/31/2019	1.92	1.83

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DEVELOPMENT OF THE LABOR ADJUSTMENT FACTOR

Productivity adjustments are required when the work being estimated will be done under conditions which differ from those applied to the data base. According to historical data and personal experience, labor productivity of an area is directly proportional to the following conditions:

1. Experience Factor
2. Economy-availability of labor
3. Project Type
4. Shutdown Requirements
5. Construction Type
6. Climate Conditions
7. Locations—skill factor of workers in the area
8. Density—number of workers per square feet

BELOW ARE BRIEF EXPLANATIONS OF THE ABOVE INEFFICIENCY FACTORS

1. Experience Factor

This is a historical factor we have accumulated for various clients and their contractors relative to the performance of a lump sum open shop contractor at a facility with little client involvement in the construction process.

2. Economy (Base = 1985 = 1.0)

Parsons E&C man-hours were developed in 1985. Adjustment to the man-hour figures are made for the inefficiencies as a result of labor availability and other work in the area relative to 1985. The source of measurement for this adjustment is Chemical Engineering Construction Labor Cost Index.

Example: 1985 to 2000 Adjustment

	1	2	2 T 1
	Base Year	Period of Construction	Adjustment
	1985	May 2008	
Index	265.3	318.9	1.202
	Rounded To-------->		1.20

3. Project Type (Base = Grassroots = 1.0)

Parsons E&C man-hours were developed from “Grassroots” projects. Adjustment to the man-hour figures are made for the inefficiencies of work because of the way it is structured. Inefficiency factors include access to the work site, work in an operating unit requiring a hot work permit, an unusually congested work site, use of construction equipment, and the type of existing unit and its condition. These adjustments are subjective and usually based upon the Estimator’s experience.

A. Revamp

The breakdown below this item is best described as a physical description of the work location. Included below are examples of how these inefficiencies are accounted for.

a. Access

This number is derived from the physical access (by personnel or machinery) to the majority of the work site location. (A 1.00 would describe a location at grade close to marshaling and storage areas, where a 1.15 would describe an elevated location, such as inside towers or columns and on top of roofs or tower platforms.)

b. Hot Work Permits

The ease in obtaining permits, along with some idea of the frequency of interruptions or delays (due to spills or releases) determines this number. (A 1.00 would describe an open area with no combustibles, corrosives, or lethal materials located in the area, which would allow routine work with no foreseeable stoppages. A 1.15 would describe a contaminated area with combustibles and/or frequent spills, where clean-up would be required.)

c. Congestion

Describes the physical proximity that equipment, piping, etc. are to each other. How cramped is the work site, what is the level of interference due to the work density, or the amount of piping, conduit, and equipment in the work area? (A 1.00 would picture an open process area such as a tank farm, while a 1.15 would represent a process area with limited space, equipment in close proximity, along with overhead piping and conduit in the area.)

d. Mobile Equipment

How accessible is the work site for hydraulic cranes, trucks or other material handling equipment. Is extensive crane matting required, or special move-in or move-out? (A 1.00 would describe a paved or hard surface with each move-in and move-out, while a 1.15 would represent a poor working surface, poor access, overhead power lines, and obstructed visibility for the operator.)

e. Plant Condition

Described as how well the facility is maintained, the age of the facility, the amount of rust, and general housekeeping practices of the facility’s staff. (A 1.00 would represent a new plant, well maintained with good housekeeping, while a 1.15 would best describe an old plant that has had little or no maintenance, has numerous leaks, corrosion problems, and is extremely cluttered.)

For the Labor Adjustment Factors form (see Attachment "A") selecting the high end of the scale for all variables would result in an overall inefficiency factor of 2.0.

4. **Shutdown (Base = 40 Hours/Week = 1.0)**

   Overtime has been shown to lower both work output and efficiency through physical fatigue and poor mental attitudes. Adjustment to the man-hour figures are made for inefficiencies on overtime work. The chart below shows inefficiency factors as a function of work days per week and work hours per day.

- Hours Worked	Inefficiency Factor	Hours Worked	Inefficiency Factor	Hours Worked	Inefficiency Factor
5-8	1.0	6-8	1.04	7-8	1.08
5-9	1.05	6-9	1.13	7-9	1.17
5-10	1.08	6-10	1.17	7-10	1.22
5-11	1.12	6-11	1.22	7-11	1.25
5-12	1.14	6-12	1.25	7-12	1.28

Source: BLS #917 Findings

5. **Construction Type (Base = Merit Shop = 1.0)**

   Adjustment to the man-hour figures are made for inefficiencies and additional staffing due to stricter discipline jurisdiction.

6. **Climate Conditions (Base = Houston Summer = 1.0)**

   The effect of Temperature on Productivity, published by National Electrical Contractors Association - 1974, is used as a guide in adjusting the man-hour figures for inefficiencies due to inclement weather conditions.

7. **Location (Base ~ Houston, Texas = 1.0)**

   Adjustment to the man-hour figures are made for inefficiencies associated with the quality of skilled craftsmen in the area in relation to Houston. Manpower Productivity Expert, Richardson Engineering Services, Inc. International Construction Factors, and in-house "Comparative Productivity Analyses" are used as a guide in determining this adjustment.

8. **Density (Base = 40 Men = 1.0)**

   Man-hour figures are adjusted for inefficiencies due to the number of workers in the area and schedule restraints. This adjustment is subjective.

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EXAMPLE:

Project: Grayling Platform H_2S
Title:
Client: Hilcorp Alaska
Date:

LABOR ADJUSTMENT FACTORS -
Alaska

A. EXPERIENCE FACTOR: (BASE = 1985 = 1.0)
ESTIMATE FOR THIS PROJECT **1.00**

B. ECONOMY: (BASE = 1985 = 1.0)
ESTIMATE FOR THIS PROJECT **1.00**

C. PROJECT TYPE: (BASE = GRASSROOTS = 1.0)

I. REVAMP:

a. ACCESS (incl elevated work)	1.00	1.03	1.06	1.09	1.12	1.15	1.00
b. HOT WORK PERMITS	1.00	1.03	1.06	1.09	1.12	1.15	1.15
c. CONGESTION	1.00	1.03	1.06	1.09	1.12	1.15	1.00
d. MOBILE EQUIPMENT	1.00	1.03	1.06	1.09	1.12	1.15	1.00
e. PLANT CONDITION	1.00	1.03	1.06	1.09	1.12	1.15	1.03

TOTAL REVAMP =(axbxcxdxe)= **1.20**

D. WORK SCHEDULE : (BASE = 70 HOURS / WEEK = 1.0) **1.28**

E. CONSTRUCTION TYPE: (BASE = MERIT SHOP = 1.0)
ESTIMATE FOR THIS PROJECT **1.00**

F. CLIMATE CONDITIONS: (BASE = HOUSTON SUMMER = 1.0)
ESTIMATE FOR THIS PROJECT **1.06**

G. LOCATION: (BASE = HOUSTON, TEXAS = 1.0)
ESTIMATE FOR THIS PROJECT - Quality of Skilled Craftmen **1.00**

H. DENSITY: (BASE = 40 MEN = 1.0)
ESTIMATE FOR THIS PROJECT **1.00**

TOTAL LABOR ADJUSTMENT FACTOR (AxBxCxDxExFxGxH) **1.62**

Round to

Hilcorp Alaska, LLC
Cook Inlet Hourly Labor Costs

Wages	**$39.05**	
(Source: BLS Occupational Employment and Wage Statistics for Alaska, Occupational Code 51-8093, May 2019)		
Productivity	**$24.21**	([Wages * 1.62] - Wages)
Overtime	**$3.75**	(Wages * 0.096)
Benefits	**$19.41**	(Wages * 0.497)
Air Transport	**$4.91**	Provided by Hilcorp
Lodging & Meals	**$4.31**	Provided by Hilcorp
Total Hourly Labor Rate	**$96**	

1.62 is the Worley-Parsons labor inefficiency adjustment factor as documented above in this appendix.
Overtime = 3.01/31.20 = 0.096 of wages [from BLS Employer Costs for Employee Compensation (Table 6)]
Benefits = (18.53-3.01)/31.20 = 0.497 of wages [from BLS Employer Costs for Employee Compensation (Table 6)]

BLS = Bureau of Labor Statistics
BLS Occupational Employment and Wage Statistics for Alaska, Occupational Code 51-8093, May 2019 and
Table 6 from the BLS Employer Costs for Employee Compensation, December 2019
are provided on the following pages of this appendix.

Occupational Employment and Wage Statistics

Occupational Employment and Wages, May 2019

51-8093 Petroleum Pump System Operators, Refinery Operators, and Gaugers

Operate or control petroleum refining or processing units. May specialize in controlling manifold and pumping systems, gauging or testing oil in storage tanks, or regulating the flow of oil into pipelines.

National estimates for this occupation
Industry profile for this occupation
Geographic profile for this occupation

National estimates for this occupation:

Employment estimate and mean wage estimates for this occupation:

Employment (1)	Employment RSE (3)	Mean hourly wage	Mean annual wage (2)	Wage RSE (3)
40,370	4.5 %	$35.49	$73,830	1.1 %

Percentile wage estimates for this occupation:

Percentile	10%	25%	50% (Median)	75%	90%
Hourly Wage	$22.78	$28.06	$35.66	$43.30	$48.11
Annual Wage (2)	$47,380	$58,370	$74,180	$90,060	$100,070

Industry profile for this occupation:

Industries with the highest published employment and wages for this occupation are provided. For a list of all industries with employment in this occupation, see the Create Customized Tables function.

Industries with the highest levels of employment in this occupation:

Industry	Employment (1)	Percent of industry employment	Hourly mean wage	Annual mean wage (2)
Petroleum and Coal Products Manufacturing	20,910	18.63	$37.27	$77,520
Oil and Gas Extraction	4,640	3.29	$34.94	$72,680
Other Pipeline Transportation	2,470	29.64	$34.46	$71,690
Pipeline Transportation of Natural Gas	2,200	7.36	$34.92	$72,640
Support Activities for Mining	1,960	0.56	$28.77	$59,850

Industries with the highest concentration of employment in this occupation:

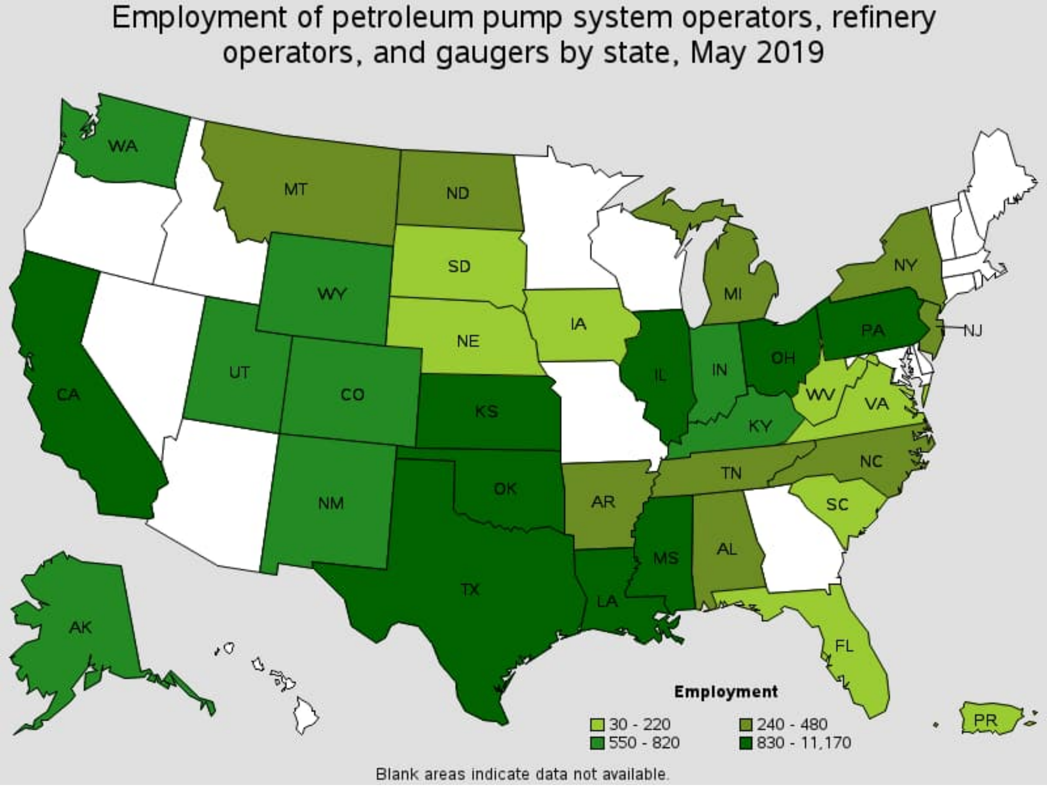
Industry	Employment (1)	Percent of industry employment	Hourly mean wage	Annual mean wage (2)
Other Pipeline Transportation	2,470	29.64	$34.46	$71,690
Petroleum and Coal Products Manufacturing	20,910	18.63	$37.27	$77,520
Pipeline Transportation of Crude Oil	1,810	15.35	$36.96	$76,870
Pipeline Transportation of Natural Gas	2,200	7.36	$34.92	$72,640
Oil and Gas Extraction	4,640	3.29	$34.94	$72,680

Top paying industries for this occupation:

Industry	Employment (1)	Percent of industry employment	Hourly mean wage	Annual mean wage (2)
Chemical Manufacturing (3251, 3252, 3253, and 3259 only)	910	0.25	$40.61	$84,470
Management of Companies and Enterprises	450	0.02	$39.93	$83,050
Architectural, Engineering, and Related Services	300	0.02	$38.65	$80,380
Petroleum and Coal Products Manufacturing	20,910	18.63	$37.27	$77,520
Pipeline Transportation of Crude Oil	1,810	15.35	$36.96	$76,870

Geographic profile for this occupation:

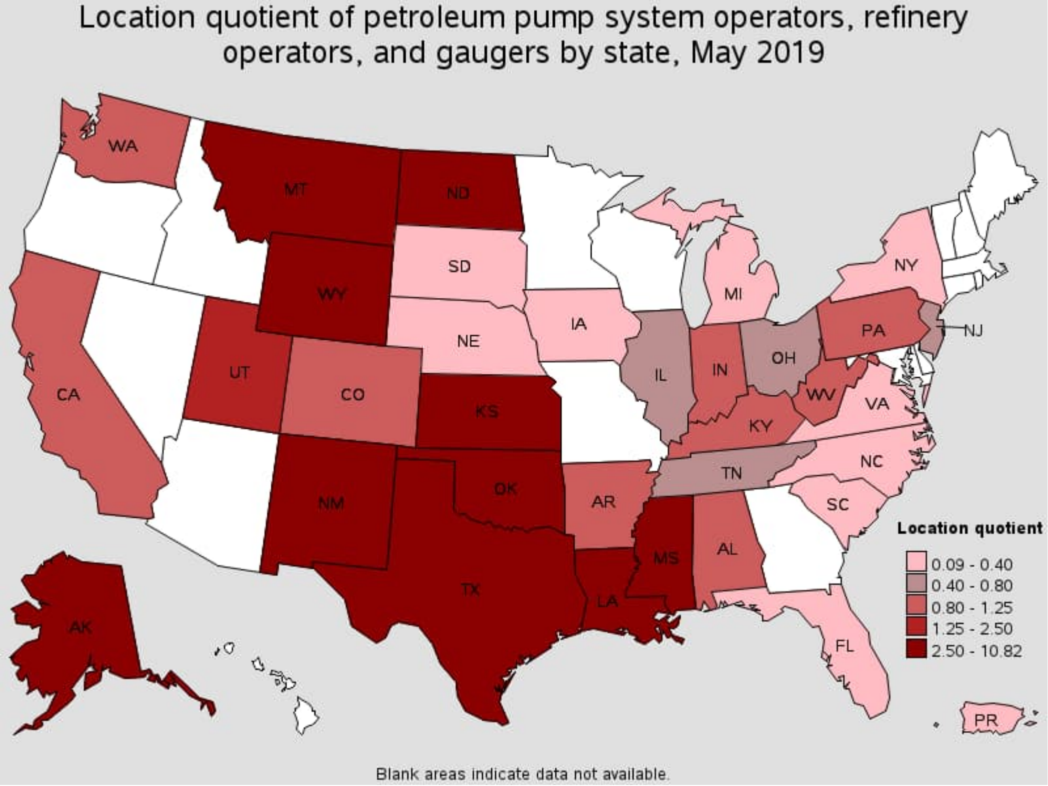
States and areas with the highest published employment, location quotients, and wages for this occupation are provided. For a list of all areas with employment in this occupation, see the Create Customized Tables function.


Employment of petroleum pump system operators, refinery operators, and gaugers by state, May 2019

Blank areas indicate data not available.

States with the highest employment level in this occupation:

State	Employment (1)	Employment per thousand jobs	Location quotient (9)	Hourly mean wage	Annual mean wage (2)
Texas	11,170	0.90	3.27	$37.14	$77,260
Louisiana	5,710	2.97	10.82	$35.25	$73,320
California	4,360	0.25	0.91	$41.67	$86,670
Oklahoma	1,980	1.23	4.46	$33.25	$69,150
Pennsylvania	1,900	0.32	1.17	$28.21	$58,680

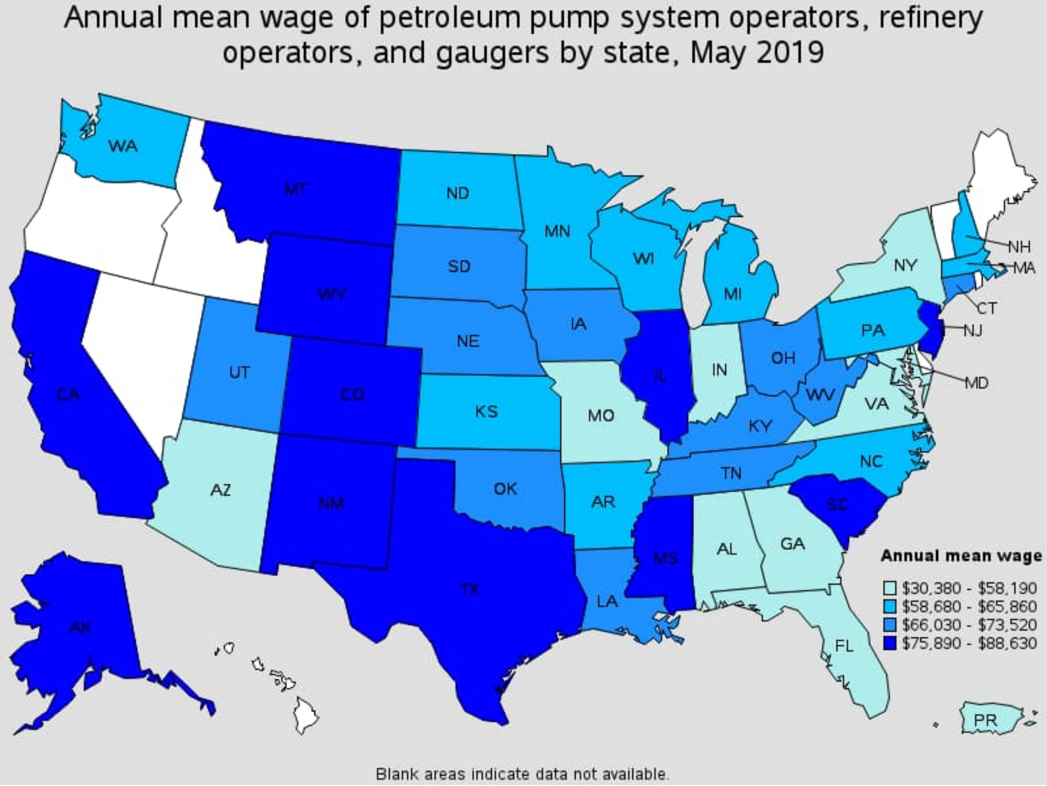


Location quotient of petroleum pump system operators, refinery operators, and gaugers by state, May 2019

Blank areas indicate data not available.

States with the highest concentration of jobs and location quotients in this occupation:

State	Employment (1)	Employment per thousand jobs	Location quotient (9)	Hourly mean wage	Annual mean wage (2)
Louisiana	5,710	2.97	10.82	$35.25	$73,320
Wyoming	730	2.68	9.77	$38.27	$79,610
Alaska	550	1.74	6.34	$39.05	$81,230
Oklahoma	1,980	1.23	4.46	$33.25	$69,150
North Dakota	470	1.12	4.07	$31.51	$65,540

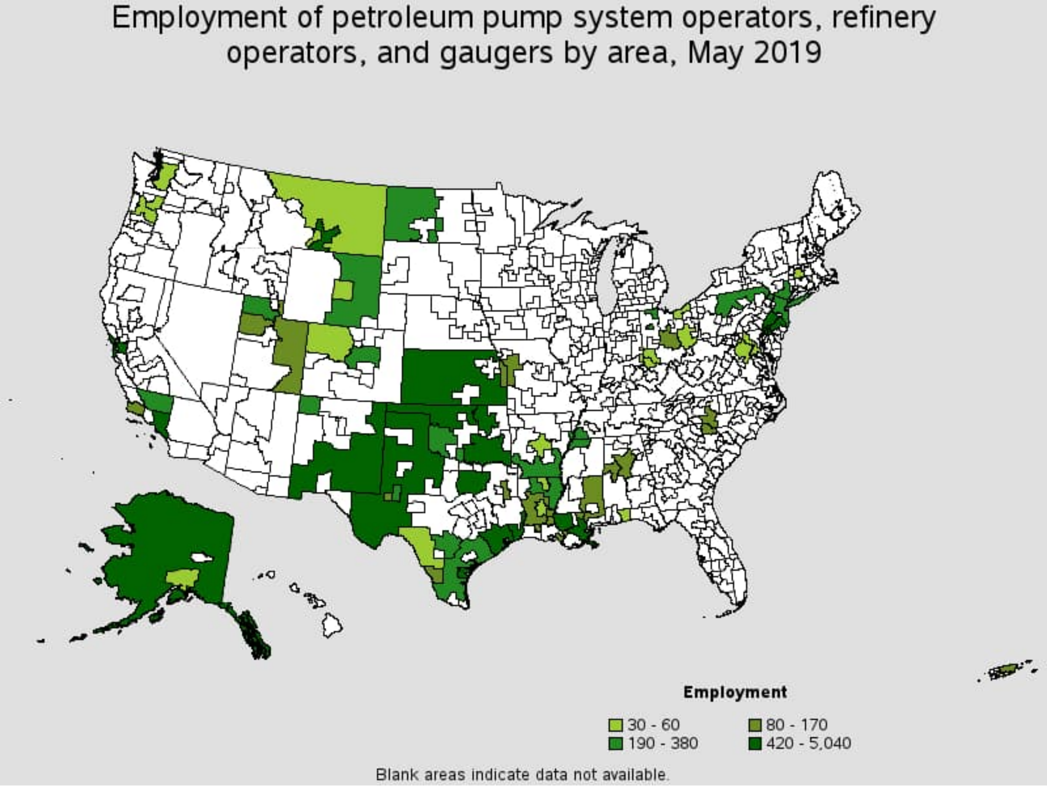


Annual mean wage of petroleum pump system operators, refinery operators, and gaugers by state, May 2019

Blank areas indicate data not available.

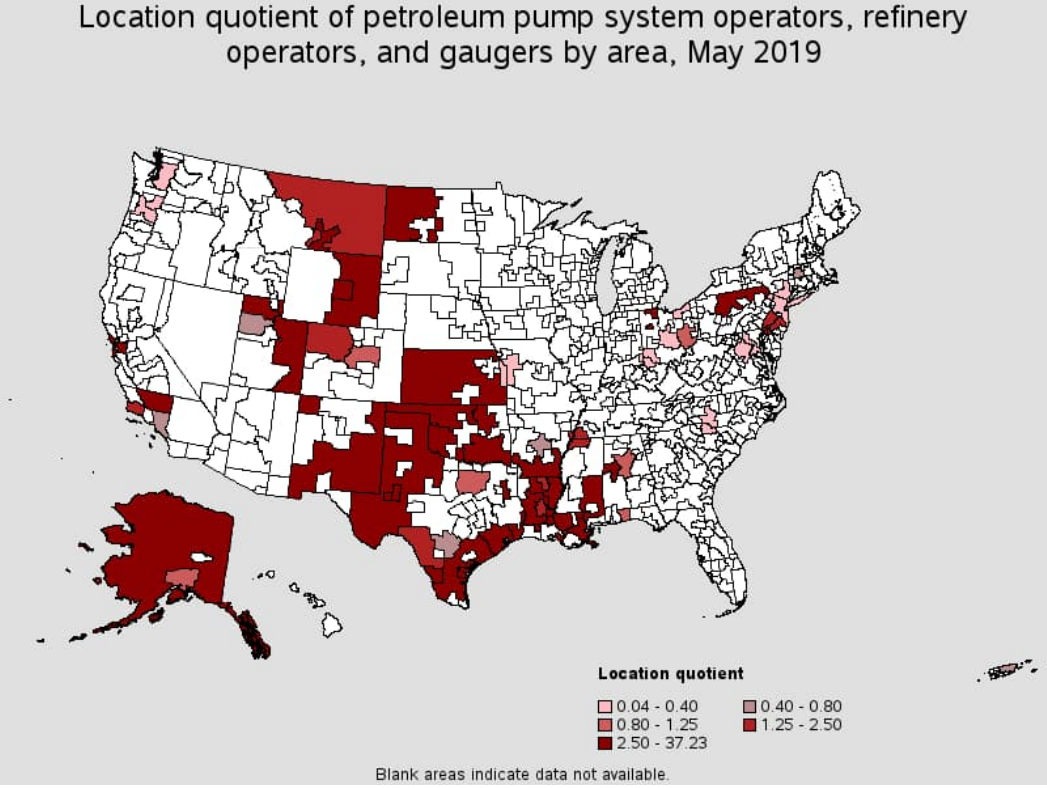
Top paying States for this occupation:

State	Employment (1)	Employment per thousand jobs	Location quotient (9)	Hourly mean wage	Annual mean wage (2)
Montana	480	1.03	3.75	$42.61	$88,630
California	4,360	0.25	0.91	$41.67	$86,670
Illinois	840	0.14	0.51	$40.27	$83,760
Colorado	590	0.22	0.81	$39.69	$82,560
Alaska	550	1.74	6.34	$39.05	$81,230



Metropolitan areas with the highest employment level in this occupation:

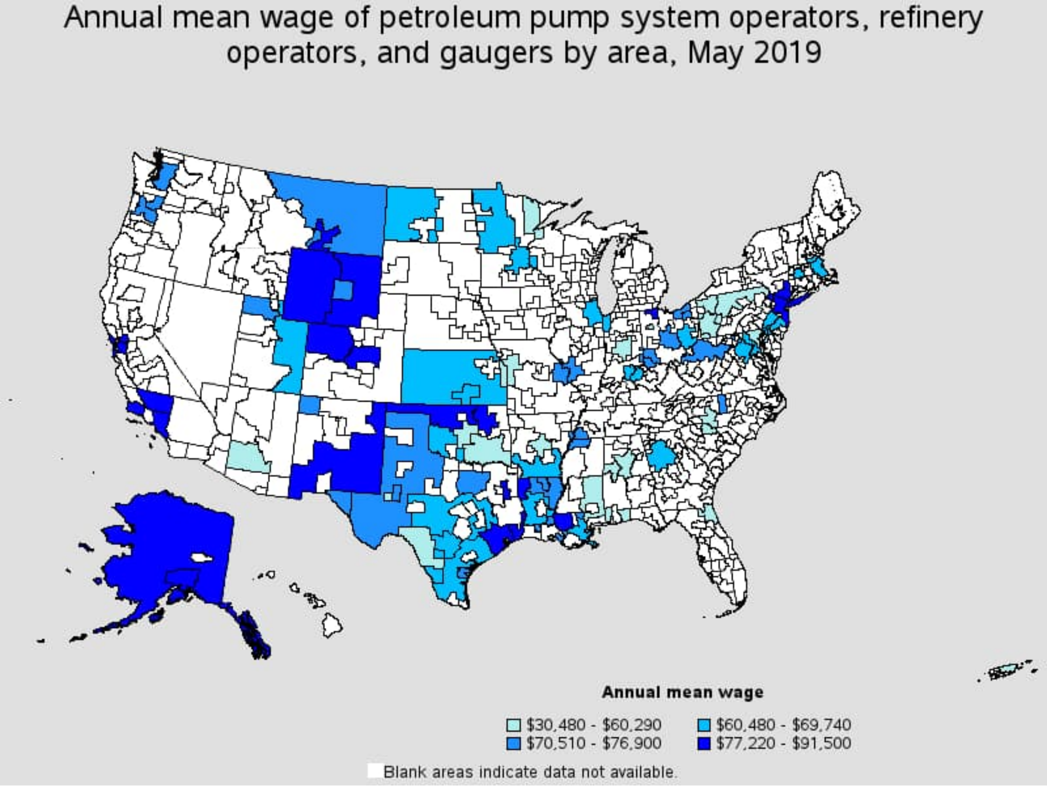
Metropolitan area	Employment (1)	Employment per thousand jobs	Location quotient (9)	Hourly mean wage	Annual mean wage (2)
Houston-The Woodlands-Sugar Land, TX	5,040	1.65	6.01	$37.85	$78,720
San Francisco-Oakland-Hayward, CA	2,250	0.91	3.32	$43.55	$90,580
New Orleans-Metairie, LA	1,800	3.23	11.76	$32.37	$67,340
Beaumont-Port Arthur, TX	1,650	10.23	37.23	$42.14	$87,660
Los Angeles-Long Beach-Anaheim, CA	1,140	0.18	0.67	$41.39	$86,100
Philadelphia-Camden-Wilmington, PA-NJ-DE-MD	1,050	0.36	1.33	$32.98	$68,590
Baton Rouge, LA	1,030	2.61	9.48	$40.25	$83,720
Corpus Christi, TX	880	4.65	16.91	$36.37	$75,650
Dallas-Fort Worth-Arlington, TX	850	0.23	0.84	$35.43	$73,690
Tulsa, OK	560	1.26	4.60	$37.24	$77,470


Location quotient of petroleum pump system operators, refinery operators, and gaugers by area, May 2019

Blank areas indicate data not available.

Metropolitan areas with the highest concentration of jobs and location quotients in this occupation:

Metropolitan area	Employment (1)	Employment per thousand jobs	Location quotient (9)	Hourly mean wage	Annual mean wage (2)
Beaumont-Port Arthur, TX	1,650	10.23	37.23	$42.14	$87,660
Billings, MT	420	4.90	17.84	$43.99	$91,500
Corpus Christi, TX	880	4.65	16.91	$36.37	$75,650
Lima, OH	210	4.23	15.39	$26.29	$54,690
Farmington, NM	190	4.06	14.76	$35.94	$74,750
New Orleans-Metairie, LA	1,800	3.23	11.76	$32.37	$67,340
Midland, TX	360	3.23	11.74	$33.99	$70,690
Baton Rouge, LA	1,030	2.61	9.48	$40.25	$83,720
Odessa, TX	170	2.04	7.41	$27.90	$58,020
Houston-The Woodlands-Sugar Land, TX	5,040	1.65	6.01	$37.85	$78,720



Annual mean wage of petroleum pump system operators, refinery operators, and gaugers by area, May 2019

Top paying metropolitan areas for this occupation:

Metropolitan area	Employment (1)	Employment per thousand jobs	Location quotient (9)	Hourly mean wage	Annual mean wage (2)
Billings, MT	420	4.90	17.84	$43.99	$91,500
San Francisco-Oakland-Hayward, CA	2,250	0.91	3.32	$43.55	$90,580
Anchorage, AK	60	0.32	1.18	$43.46	$90,400
Denver-Aurora-Lakewood, CO	340	0.23	0.82	$42.90	$89,230
Beaumont-Port Arthur, TX	1,650	10.23	37.23	$42.14	$87,660
Santa Maria-Santa Barbara, CA	110	0.57	2.09	$41.97	$87,290
Los Angeles-Long Beach-Anaheim, CA	1,140	0.18	0.67	$41.39	$86,100
Toledo, OH	380	1.27	4.61	$41.18	$85,650
Baton Rouge, LA	1,030	2.61	9.48	$40.25	$83,720
Bakersfield, CA	360	1.14	4.13	$39.76	$82,700

Nonmetropolitan areas with the highest employment in this occupation:

Nonmetropolitan area	Employment (1)	Employment per thousand jobs	Location quotient (9)	Hourly mean wage	Annual mean wage (2)
West Texas Region of Texas nonmetropolitan area	780	3.88	14.13	$35.48	$73,800
Kansas nonmetropolitan area	650	1.65	5.99	$30.01	$62,420
Eastern New Mexico nonmetropolitan area	540	3.29	11.99	$37.12	$77,220
Southeast Oklahoma nonmetropolitan area	480	2.86	10.39	$28.99	$60,290
Alaska nonmetropolitan area	480	4.40	16.00	$38.60	$80,290

Nonmetropolitan areas with the highest concentration of jobs and location quotients in this occupation:

Nonmetropolitan area	Employment (1)	Employment per thousand jobs	Location quotient (9)	Hourly mean wage	Annual mean wage (2)
Alaska nonmetropolitan area	480	4.40	16.00	$38.60	$80,290
Northwest Oklahoma nonmetropolitan area	420	4.26	15.51	$37.77	$78,560
Eastern Wyoming nonmetropolitan area	360	4.19	15.25	$38.00	$79,050

West Texas Region of Texas nonmetropolitan area	780	3.88	14.13	$35.48	$73,800
Southwest Oklahoma nonmetropolitan area	220	3.42	12.45	$29.08	$60,480

Top paying nonmetropolitan areas for this occupation:

Nonmetropolitan area	Employment (1)	Employment per thousand jobs	Location quotient (9)	Hourly mean wage	Annual mean wage (2)
Northwest Colorado nonmetropolitan area	50	0.39	1.40	$41.84	$87,030
Alaska nonmetropolitan area	480	4.40	16.00	$38.60	$80,290
Eastern Wyoming nonmetropolitan area	360	4.19	15.25	$38.00	$79,050
Northwest Oklahoma nonmetropolitan area	420	4.26	15.51	$37.77	$78,560
Western Wyoming nonmetropolitan area	(8)	(8)	(8)	$37.76	$78,540

About May 2019 National, State, Metropolitan, and Nonmetropolitan Area Occupational Employment and Wage Estimates

These estimates are calculated with data collected from employers in all industry sectors, all metropolitan and nonmetropolitan areas, and all states and the District of Columbia. The top employment and wage figures are provided above. The complete list is available in the downloadable XLS files.

The percentile wage estimate is the value of a wage below which a certain percent of workers fall. The median wage is the 50th percentile wage estimate--50 percent of workers earn less than the median and 50 percent of workers earn more than the median. More about percentile wages.

(1) Estimates for detailed occupations do not sum to the totals because the totals include occupations not shown separately. Estimates do not include self-employed workers.

(2) Annual wages have been calculated by multiplying the hourly mean wage by a "year-round, full-time" hours figure of 2,080 hours; for those occupations where there is not an hourly wage published, the annual wage has been directly calculated from the reported survey data.

(3) The relative standard error (RSE) is a measure of the reliability of a survey statistic. The smaller the relative standard error, the more precise the estimate.

(8) Estimate not released.

(9) The location quotient is the ratio of the area concentration of occupational employment to the national average concentration. A location quotient greater than one indicates the occupation has a higher share of employment than average, and a location quotient less than one indicates the occupation is less prevalent in the area than average.

Other OES estimates and related information:

May 2019 National Occupational Employment and Wage Estimates

May 2019 State Occupational Employment and Wage Estimates

May 2019 Metropolitan and Nonmetropolitan Area Occupational Employment and Wage Estimates

May 2019 National Industry-Specific Occupational Employment and Wage Estimates

May 2019 Occupation Profiles

Technical Notes

Last Modified Date: July 6, 2020

U.S. BUREAU OF LABOR STATISTICS Division of Occupational Employment and Wage Statistics PSB Suite 2135 2 Massachusetts Avenue NE Washington, DC 20212-0001

Telephone:1-202-691-6569 www.bls.gov/OES Contact OEWS

Table 6. Employer Costs for Employee Compensation for private industry workers by establishment size and industry group

[Dec. 2019]

Series	Total compensation[1]		Wages and salaries		Total benefits		Paid leave		Supplemental pay		Insurance		Retirement and savings		Legally required benefits	
	Cost ($)	Percent	Cost ($)	Percent	Cost ($)	Percent	Cost ($)	Percent	Cost ($)	Percent	Cost ($)	Percent	Cost ($)	Percent	Cost ($)	Percent
All workers																
1-99 workers	28.77	100.0	21.27	73.9	7.50	26.1	1.78	6.2	0.74	2.6	1.89	6.6	0.70	2.4	2.39	8.3
1-49 workers	27.84	100.0	20.84	74.9	7.00	25.1	1.67	6.0	0.68	2.5	1.70	6.1	0.60	2.1	2.34	8.4
50-99 workers	31.96	100.0	22.73	71.1	9.23	28.9	2.14	6.7	0.94	2.9	2.56	8.0	1.04	3.2	2.55	8.0
100 workers or more	41.75	100.0	28.01	67.1	13.75	32.9	3.42	8.2	1.71	4.1	3.79	9.1	1.85	4.4	2.98	7.1
100-499 workers	35.86	100.0	24.86	69.3	11.00	30.7	2.68	7.5	1.16	3.2	3.10	8.7	1.33	3.7	2.73	7.6
500 workers or more	49.46	100.0	32.12	64.9	17.34	35.1	4.39	8.9	2.43	4.9	4.70	9.5	2.53	5.1	3.30	6.7
Goods-producing[2]																
1-99 workers	33.95	100.0	24.04	70.8	9.92	29.2	1.72	5.1	1.19	3.5	2.65	7.8	1.17	3.4	3.19	9.4
1-49 workers	32.34	100.0	23.31	72.1	9.03	27.9	1.52	4.7	1.11	3.4	2.27	7.0	0.98	3.0	3.16	9.8
50-99 workers	37.77	100.0	25.75	68.2	12.02	31.8	2.22	5.9	1.36	3.6	3.56	9.4	1.61	4.3	3.27	8.6
100 workers or more	45.10	100.0	29.21	64.8	15.89	35.2	3.32	7.4	2.22	4.9	4.57	10.1	2.29	5.1	3.49	7.7
100-499 workers	42.15	100.0	27.94	66.3	14.21	33.7	2.91	6.9	1.71	4.1	4.14	9.8	2.04	4.8	3.41	8.1
500 workers or more	49.74	100.0	31.20	62.7	18.53	37.3	3.95	7.9	3.01	6.1	5.25	10.6	2.70	5.4	3.61	7.3
Service-providing[3]																
1-99 workers	27.89	100.0	20.80	74.6	7.09	25.4	1.79	6.4	0.67	2.4	1.77	6.3	0.62	2.2	2.26	8.1
1-49 workers	27.16	100.0	20.47	75.4	6.69	24.6	1.69	6.2	0.62	2.3	1.61	5.9	0.54	2.0	2.22	8.2
50-99 workers	30.61	100.0	22.02	72.0	8.58	28.0	2.12	6.9	0.84	2.8	2.33	7.6	0.90	2.9	2.39	7.8
100 workers or more	40.94	100.0	27.71	67.7	13.23	32.3	3.45	8.4	1.58	3.9	3.60	8.8	1.74	4.2	2.85	7.0
100-499 workers	34.18	100.0	24.03	70.3	10.14	29.7	2.62	7.7	1.01	3.0	2.83	8.3	1.14	3.3	2.55	7.5
500 workers or more	49.40	100.0	32.32	65.4	17.08	34.6	4.48	9.1	2.30	4.7	4.58	9.3	2.49	5.0	3.23	6.5

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[1] Includes costs for wages and salaries and benefits.

[2] Includes mining, construction, and manufacturing. The agriculture, forestry, farming, and hunting sector is excluded.

[3] Includes utilities; wholesale trade; retail trade; transportation and warehousing; information; finance and insurance; real estate and rental and leasing; professional and technical services; management of companies and enterprises; administrative and waste services; educational services; health care and social assistance; arts, entertainment and recreation; accommodation and food services; and other services, except public administration.

Hilcorp Alaska, LLC
Grayling Platform Electricity Cost

	Grayling	
TBO	40000	hrs
Overhaul Costs	$990,000	
Gas Costs	$7.83	per 1000 cu ft
Total Power Generated	4160	kWe
Average Amb Temperature	32	ºF
Turbine Load	4160	
Corrected Turbine Load	4,273	kWe
Corrected Heat Consumption	52.7	MMBtu/hr
Site Heat Consumption	51.3	MMBtu/hr
Gas Usage	46.594005	Mscfh
Gas Cost	$364.83	per hr
Overhaul Cost	$24.75	per hr
Maintenance Cost	$1.87	per hr
Total Cost	$0.094	per kW-hr

[$364.83 + $24.75 + $1.87] / 4,160 kWe-hr = $0.094 / kW-hr

From:	Greg Arthur <Greg.Arthur@hilcorp.com>
Sent:	October 08, 2020 1:11 PM
To:	Jeanette Brena; Krystin McClure
Cc:	Isaac Bertschi
Subject:	FW: Grayling H2S treatment
Attachments:	GA 2019-02_Grayling Trap Gas.pdf; G-F-1015-001_00-Model.pdf; G-F-1015-002_00-Model.pdf; G-F-1015-003_00-Model.pdf; G-F-1015-004_00-Model.pdf; G-F-1015-005_01-Model.pdf

Here's the information for the Grayling platform.

From: Aaron Douget
Sent: Thursday, October 8, 2020 4:13 AM
To: Greg Arthur <Greg.Arthur@hilcorp.com>
Cc: Mark McKinley <mmckinley@hilcorp.com>; Jon Collins <jocollins@hilcorp.com>; Mike Abbott <mabbott@hilcorp.com>
Subject: Grayling H2S treatment

Greg,

Following up from our conversation about Grayling H2S treatment.

- The Grayling package was purchased from Compass compression project # C-760. This unit has a reciprocating gas compressor as well as a sweeting skid, but it was purchased together as one package. H2S treatment portion manufactured by Ultrafab. Attached are the PIDs for this package.
- The inlet to the skid varies from 750ppm -1400 ppm H2S levels. Gas pressure leaving the compressor and entering the treatment skid is approximately 250 PSIG. The inlet temperature varies between 90-130 degrees depending on ambient conditions. Flow rate varies between 800mcf- 1200mcf.
- Attached is a copy of the last gas sample, we have sample bottles that we will have analyzed shortly so we can have up to date data for this.
- H2S treating Chemical comes from Schlumberger : Summer blend HR-2619 @ $7.69 per gal, Winter blend HR-29715 @ $7.93 per gal. Chemical rate ranges from 80-130 GPD.

Let me know what other information we can provide to keep this moving forward.

Regards,

Aaron Douget
Production Foreman
Grayling Platform
Phone: (907) 776-6630
Cell: (870) 404-5696
Email: adouget@hilcorp.com

Hilcorp Alaska

Jeff Alger

From: Aaron Douget <adouget@hilcorp.com>
Sent: March 09, 2021 2:41 PM
To: Jeff Alger
Cc: Mike Abbott; Jon Collins; Greg Arthur
Subject: RE: [EXTERNAL] Grayling H2S Increase Application
Attachments: 20210309122848819.pdf

Jeff,

Attached is some information from the compressor set attached to the sweetening unit. As we discussed on the phone, the system does have the capacity to sweeten all of the formation gas.

As for the power generation questions:

- TBO for the primary power generator (Solar T60 SoLoNox unit) is 40k hours as per manufacturer recommendation.
- The cost of the overhaul in 2020 was approximately $990,000 including components and labor.
- I was estimate the annual man hours for standard maintenance on the T60 to be 180 hours. Again, as discussed, this number only incorporates the general maintenance performed on the T60 unit and not the smaller units. This number is assuming standard planned maintenance and not abnormal events.

Let me know if you need anything else.

Regards,

Aaron Douget
Production Foreman
Grayling Platform
Phone: (907) 776-6630
Cell: (870) 404-5696
Email: adouget@hilcorp.com

Jeff Alger

From: Bill Wolverton <William.Wolverton@hilcorp.com>
Sent: November 20, 2020 3:27 PM
To: Jeanette Brena
Cc: Krystin McClure
Subject: RE: [EXTERNAL] Re: Cost Estimates - Delivery to Steelhead Platform

Jeanette,
I'm sorry that there isn't an easy answer to your inquiry.
I'm really just took a WAG at the estimate not knowing where your water supplier was located, whether you needed transport all the way from origin to the platform or just from the OSK Dock to the Platform, or what volume, (Quantity of truck loads, or number of boat loads), of construction materials you have to accompany the water delivery for the project.
My misunderstanding was that Potable H2O delivered by the internal tankage of the boat and pumped up to some tankage staged on the platform deck - was then going to be processed by reverse osmosis aboard the platform.
(Providing me a project summary or SOW may help in estimating logistics costs better for you.)
The internal boat tanks are for potable water and drill water only. The prospect of cleaning those tanks to take on deionized water without comingling (contaminating) with some potable in the boat's tanks is highly improbable.
To insure purity of the product, I'd suggest using clean and lined IMO (ISO) ~5,000 gal transport tanks.
These tanks are commonly used for Bulk liquids deliveries to Platforms, and are certified for lifting full to and from boats.
Weaver Brothers has an available iinventory of these lined IMO tanks. They rent for $85/day.
These ISO's would be trucked to the filling point on "chassis trailers", and then delivered full to the dock.
Weavers has the chassis trailers.
The tanks would then be swung full, by crane, onto the boat for transport to the platform.
The platform crane would lift them off the boat and set them to the Platform deck.
The Platform would have to verify the exact deck loading allowance for the exact deck location(s) that these tanks would need to be landed for the project.
(Since total loaded weight shouldn't exceed 50,000 lbs per tank, the boats will have no issues hauling them, but the Platform may need to spread the full tanks out across their decks.)
Our boat charter is on a multi-year term, and the contract pricing of Dock Services (including water) is secure between Hilcorp and namely OMS,LLC for boats, and OSK for the Dock.
There isn't a clean per day charter cost exclusive of cargo weight shipped, (called wharfage.)
The finalized charges for the vessel are based on the monthly vessel bill allocated out by wharfage combined with the longshore costs, also allocated by wharfage, across all platforms & projects that were supported.
(I'd have to refer to legal to release any secure contract pricing.)
Estimates of this nature therefore have to be heavily influenced by sheer experience of costs involved in similar previous operations.
I buffered my earlier estimate to allow for variables, such as overtime vs. straight time dock labor (dependent on tide cycles), weather delays that impact boats, or shipping delays of loads headed to the dock, and whether any other projects or platforms share in the wharfage, or any following vessel usage, of the boat that day.
For cost of reverse osmosis treated, or demineralized, H2O in that 20,000 gal quantity, I would have to refer you to an actual supplier for a quote per gallon, like Univar maybe?
(I mention demineralized because that is what I have purchased from Univar in the past in lieu of distilled water for Turbine Wash operations.)
I have no idea what price per gallon delivered to the dock would be, but Univar fills drums of demineralized water in Anchorage so I imagine they could fill ISO/IMO tanks.
Cold weather and freezing temps could pose a challenge if done in the winter months too. I don't believe any of the Plastic Lined IMO tanks have steam coils installed to heat the contents.

Anyhow, I recommend using the IMO (ISO) Tankage method for transport , because cranes are the only means to mov
tanks from the boat up the Platform, much like how bulk chemicals would be handled.
The trip from the OSK Dock to the Steelhead is usually less than 2 hours.
If there are any other details as to the project SOW and timing, volume of associated construction materials, or comments as to whether the Transport Tanks would or would not work in this application, please feel free to send me feedback.
Thank you,

Bill Wolverton
Hilcorp Logistics Supervisor
OSK Dock
907-776-6725

To: Jeanette Brena <jbrena@slrconsulting.com>
Cc: Zane Fallon <zfallon@hilcorp.com>; Ryan Hendriks <rhendriks@hilcorp.com>
Subject: RE: [EXTERNAL] Re: Cost Estimates - Delivery to Steelhead Platform

Good day Jeanette,

For budgetary estimate purposes, please allow $18,000 boat cost to your AFE or Project to cover the shipment of the 20,000 gal tank offshore from the OSK Dock, with the delivery of construction of materials and supplies and a follow-up boat run to deliver the Potable water (20K USG), and a boat to backhaul the tools to the dock for return to vendor(s). The water itself is only $3.50 per 1K USG, but the boat charter cost, boat fuel, and dock fees comprise the bulk of the expenses involved.

If you have any concerns, please reach out.

Thanks,

Bill Wolverton
Hilcorp Logistics Supervisor
OSK Dock
907-776-6725

Grayling Platform
Gas Saturation

Temp	120			
Pressure	394.7		1.695	
Methane	0.54813		0.545781	
Ethane	0.0738		0.073484	
Propane	0.09965		0.099223	
i-Butane	0.03064		0.030509	
n-Butane	0.06596		0.065677	
i-Pentane	0.01884		0.018759	
n-Pentane	0.02006		0.019974	
C6+	0.0155		0.015434	
Moisture	0.004294	1.695	0.004276	
Nitrogen	0.11112		0.110644	
Carbon Dioxide	0.01631		0.01624	
Formation Gas	2.1	5532.139	3180.416	gal/day

5532.139	moles gas per day
0.004276	moles Water per mole gas
426.1757	lbs water/day
51.06959	Gal water/day
24.31885	gal/MMscf

Grayling Platform

Fuel Gas H_2S Increase Project Construction Permit Application

Attachment D – Permit Revisions Request

Hilcorp Alaska, LLC

3800 Centerpoint Drive, Suite 1400, Anchorage, Alaska, 99503

Prepared by:

SLR International Corporation

2700 Gambell Street, Suite 200, Anchorage, Alaska, 99503

SLR Project No.: 105.00874.20026

October 2023

Grayling Platform
Fuel Gas H_2S Increase Project
Construction Permit Application
Attachment D – Permit Revisions Request

Prepared for:

Hilcorp Alaska, LLC
3800 Centerpoint Drive, Suite 1400
Anchorage, AK 99503

This document has been prepared by SLR International Corporation (SLR). The material and data in this report were prepared under the supervision and direction of the undersigned.

TA DAMIANA

Tom Damiana
Principal Engineer

Sims Duggins
Senior Principal

Table of Contents

D1. Application to Revise Title I Terms and Conditions 18 AAC 50.508(6) D1-1

D1.1 18 AAC 50.540(k)(1) – A Copy of the Title I Permit that Established the Permit Term or Condition D1-1

D1.2 18 AAC 50.540(k)(2) – An Explanation of Why the Permit Term or Condition Should be Revised or Rescinded D1-1

D1.3 18 AAC 50.540(k)(3) – The Effect of Revising or Revoking the Permit Term or Conditions D1-2

D1.3.1 18 AAC 50.540(k)(3)(A) – Effect on Source Emissions D1-2

D1.3.2 18 AAC 50.540(k)(3)(B) – Effect on Other Permit Terms D1-3

D1.3.3 18 AAC 50.540(k)(3)(C) – Effect on the Underlying Ambient Demonstration D1-3

D1.3.4 18 AAC 50.540(k)(3)(D) – Effect on Compliance Monitoring D1-3

D1.4 18 AAC 50.540(k)(4) – Revising Conditions that Allow for Avoidance of a Permit Classification D1-3

Appendices

Appendix A Updated SO_2 Assessable PTE

D1. Application to Revise Title I Terms and Conditions 18 AAC 50.508(6)

This attachment provides the information required to revise certain Title I terms and conditions of Minor Source-Specific Permit AQ0069MSS04, Rev 1 for the Grayling Platform under the provisions of 18 AAC 50.508(6), including a basis for each proposed action, and the effect the requested revisions will have on emissions, other permit terms, air quality compliance, and compliance monitoring as required under 18 AAC 50.540(k) for applications under 18 AAC 50.508(6).

D1.1 18 AAC 50.540(k)(1) – A Copy of the Title I Permit that Established the Permit Term or Condition

A copy of the Title I permit that establishes the permit terms and conditions being revised or rescinded (Minor Source-Specific Permit AQ0069MSS04, Rev 1) is provided in **Attachment G** of this application.

D1.2 18 AAC 50.540(k)(2) – An Explanation of Why the Permit Term or Condition Should be Revised or Rescinded

The following discussion identifies the permit conditions that should be revised or rescinded and provides the basis for the requested revisions:

1. **Condition 3.1:** This condition states that the stationary source's assessable potential to emit (PTE) is 1,159 tpy. Hilcorp North Slope applied to renew Title V Operating Permit no. AQ0069TVP03 in December 2022. The Title V permit application included emissions calculations to estimate the Grayling Platform PTE and the assessable PTE was revised with that application to be 753.6 tpy. This is also the value documented in Table C of the Statement of Basis for Operating Permit no. AQ0069TVP04, which was issued in June 2023. The assessable PTE value is to be revised because of the 650 ppmv fuel gas H_2S content BACT limit, annual average, and corresponding annual SO_2 emissions BACT limit of 98 tpy that are to be set as established by this application for the Grayling Platform Fuel Gas H_2S Increase Project. Only the SO_2 PTE will change in conjunction with this application. All other potential pollutant emission rates remain the same. The resulting new total assessable PTE is 771.8 tpy with the SO_2 assessable PTE increasing from 109.6 tpy to 127.7 tpy. A printed copy of the updated version of Table D.8a from the emissions calculations spreadsheet of the December 2022 Title V permit renewal application, which addresses the change in limited potential SO_2 emissions that will result from the Grayling Platform Fuel Gas H_2S Increase Project, is provided in **Appendix A** of this section of the application. An electronic copy of the updated emissions spreadsheet is also provided as described in **Attachment A-2** of this application.
2. **Condition 9:** This condition establishes a fuel gas H_2S limit of 400 ppmv, monthly average, to protect ambient air quality. This limit was based on a previously submitted ambient air quality impact assessment. This condition should be revised to increase the monthly average limit to 1,250 ppmv based on the results of the new ambient air quality impact assessment conducted for the platform in conjunction with this application. **See Attachment F** of this application.

3. **New Condition**: A new condition will need to be added to the permit to establish the annual average fuel gas H_2S and SO_2 BACT emissions limits of 650 ppmv and 98 tpy, respectively. The 98 tpy SO_2 emissions limit applies to all fuel gas burned by gas-fired significant emissions units located on the Grayling Platform.
4. **Condition 9.2:** This condition establishes the monitoring frequency for measuring the fuel gas H_2S concentration based on a trigger level set at 85% of the maximum allowable concentration. The H_2S trigger level should be increased to 1,063 ppmv consistent with the new ambient air quality protection limit requested under Condition 9 or, perhaps more appropriately, to 553 ppmv consistent with the BACT limit set by the new condition described above.
5. **Condition 11:** This condition establishes monitoring necessary to determine the net change in emissions associated with fuel gas combustion as H_2S values and fuel gas volumes increase in the future to satisfy the requirements of 40 C.F.R. 52.21(r)(6). This condition was included in the permit as part of projected SO_2 increases associated with increasing the source-wide fuel gas H_2S ambient protection limit from 250 ppmv to 400 ppmv. The provisions of 40 C.F.R. 52.21(r)(6) apply with respect to any regulated NSR pollutant emitted from projects for existing EUs at a major stationary source in circumstances where there is a reasonable possibility that a project that is not part of a major modification may result in a significant emissions increase of that pollutant. The requirements include additional monitoring, recordkeeping, reporting, and calculation of the net change in emissions each calendar year during the 10-year period following resumption of regular operation after the change to determine if the project was actually a PSD major modification under 40 C.F.R. 52.21(b)(2). Since the prior fuel gas H_2S increase permitting action falls within the contemporaneous period of the current PSD modification, following the current modification there will no longer be a need to calculate the net change in emissions under 40 C.F.R. 52.21(r)(6) and Condition 11 should be rescinded.
6. **Condition 12:** This condition establishes recordkeeping associated with Condition 11. Condition 11 will be rescinded; therefore, Condition 12 is no longer necessary and should also be rescinded.
7. **Condition 13:** This condition establishes reporting associated with Condition 11. Condition 11 will be rescinded; therefore, Condition 13 is no longer necessary and should also be rescinded.

D1.3 18 AAC 50.540(k)(3) – The Effect of Revising or Revoking the Permit Term or Conditions

18 AAC 50.540(K)(3) requires discussing the effect of the requested revisions on emissions, other permit terms, the underlying ambient demonstration, and compliance monitoring.

D1.3.1 18 AAC 50.540(k)(3)(A) – Effect on Source Emissions

Revising Condition 9 to increase the fuel gas H_2S ambient air quality protection limit and establishing a new fuel gas H_2S BACT limit will increase the source's SO_2 potential to emit. Derivation of the revised SO_2 potential to emit, which is based on the requested fuel gas H_2S BACT limit of 650 ppmv not the requested new ambient air quality protection limit of 1,250 ppmv, is detailed in **Attachment B** of this application and the new stationary source wide

SO_2 PTE is shown in **Appendix A** of this section of the application. No other requested revision to the permit will influence source emissions.

D1.3.2 18 AAC 50.540(k)(3)(B) – Effect on Other Permit Terms

The proposed revisions to Conditions 3.1, 9, 9.2, 11, 12, and 13 will have no effect on other permit terms.

D1.3.3 18 AAC 50.540(k)(3)(C) – Effect on the Underlying Ambient Demonstration

Revising Condition 9 to increase the fuel gas H_2S limit has the potential to increase source SO_2 and $PM_{2.5}$ impacts. An ambient air quality impact assessment based on dispersion modeling is provided in **Attachment F** of this application. The assessment shows that following the increase, impacts from the project will be below applicable air quality standards and PSD increments. The proposed revisions to Conditions 3.1, 9.2, 11, 12, and 13 have no effect on the underlying ambient demonstration.

D1.3.4 18 AAC 50.540(k)(3)(D) – Effect on Compliance Monitoring

Revising Condition 9 to increase the fuel gas H_2S limit will increase the H_2S concentration that triggers an increase in the monitoring frequency specified in Condition 9.2. As a result, a revision to Condition 9.2 is also requested. The compliance monitoring in Condition 11 will not be necessary following this permit action and should be rescinded. The proposed revisions to Conditions 3.1, 12 and 13 will have no effect on compliance monitoring.

D1.4 18 AAC 50.540(k)(4) – Revising Conditions that Allow for Avoidance of a Permit Classification

None of the requested revisions apply to conditions that address avoidance of a permit classification.

Appendix A Updated SO_2 Assessable PTE

Grayling Platform

Fuel Gas H_2S Increase Project
Construction Permit Application
Attachment D – Permit Revisions Request

Hilcorp Alaska, LLC

SLR Project No.: 105.00874.20026

October 2023

Table D.8a. Significant Emissions Unit Inventory - SO_2 Emissions

(Updated to Reflect Changes Resulting from the Grayling Platform Fuel Gas H_2S Increase Project)

Hilcorp Alaska, LLC - Grayling Platform

EU ID	Emissions Unit Name	Fuel	Rating/Size		Reference	Emission Factor	Limited Potential Emissions	Unlimited Potential Emissions	Estimated Actual Emissions
1	Solar Centaur T4500	Fuel Gas	4,500	hp	Mass Balance	650 ppmv H_2S	98.0 tpy	19.0 tpy	6.5 tpy
3	Solar Centaur T4500	Fuel Gas	4,500	hp	Mass Balance	650 ppmv H_2S		19.0 tpy	5.1 tpy
4a	Solar Centaur T4500	Fuel Gas	4,500	hp	Mass Balance	650 ppmv H_2S		19.0 tpy	18.6 tpy
14	Solar Saturn T1200	Fuel Gas	1,100	hp	Mass Balance	650 ppmv H_2S		5.8 tpy	0 tpy
15	Solar Saturn T1200	Fuel Gas	800	kW	Mass Balance	650 ppmv H_2S		6.1 tpy	1.1 tpy
16	Solar Saturn T1200	Fuel Gas	750	kW	Mass Balance	650 ppmv H_2S		5.7 tpy	1.2 tpy
17	Solar Saturn T1200	Fuel Gas	800	kW	Mass Balance	650 ppmv H_2S		6.1 tpy	1.0 tpy
18	Solar Saturn T1200	Fuel Gas	800	kW	Mass Balance	650 ppmv H_2S		6.1 tpy	1.0 tpy
28	Flare (South)	Fuel Gas	0.12	MMscf/day, pilot/purge combined	Mass Balance	650 ppmv H_2S		564.8 tpy	2.7 tpy
29	Flare (SW)	Fuel Gas	14	MMscf/day, emergency each					
31	Solar Taurus 60 T-7300S	Fuel Gas	5.2	MW	Mass Balance	650 ppmv H_2S		37.1 tpy	31.1 tpy
24	Caterpillar 3406	Diesel	340	hp	Mass Balance	0.5 wt.%S	1.8 tpy	5.3 tpy	9.4E-02 tpy
25	Caterpillar 3208	Diesel	250	hp	Mass Balance	0.5 wt.%S	1.3 tpy	3.9 tpy	0.2 tpy
26a	Detroit Diesel Series 60 6063HV35	Diesel	685	hp	Mass Balance	0.5 wt.%S	0.6 tpy	10.7 tpy	1.2E-03 tpy
27	Caterpillar D-330C	Diesel	85	hp	Mass Balance	0.5 wt.%S	0.5 tpy	1.3 tpy	3.0E-03 tpy
						Total	**102.2 tpy**	**710.0 tpy**	**68.7 tpy**

Table D.8b. Insignificant Emissions Unit Inventory - SO_2 Emissions

Hilcorp Alaska, LLC - Grayling Platform

EU ID	Emissions Unit Name	Fuel	Rating/Size		Reference	Emission Factor	Unlimited Potential Emissions
N/A	Clayton ROG-60-1 Boiler	Fuel Gas	2.5	MMBtu/hr	Mass Balance	650 ppmv H_2S	1.2 tpy
N/A	Portable Space Heaters	Diesel	8	MMBtu/hr	Mass Balance	0.5 wt.%S	17.9 tpy
N/A	Clayton Sigma Fire	Fuel Gas	50	bhp	Mass Balance	650 ppmv H_2S	0.8 tpy
19a	Riello AR 400 Boiler	Fuel Gas	4	MMBtu/hr	Mass Balance	650 ppmv H_2S	1.9 tpy
19b	Riello AR 400 Boiler	Fuel Gas	4	MMBtu/hr	Mass Balance	650 ppmv H_2S	1.9 tpy
20a	Riello AR 400 Boiler	Fuel Gas	4	MMBtu/hr	Mass Balance	650 ppmv H_2S	1.9 tpy
N/A	Diesel Fuel Tank (G-T-3090)	N/A	2,547	barrels	Mass Balance	3 turnovers/yr	0 tpy
						Total	**25.5 tpy**

Conversions:

EU IDs 1, 3, 4a Heat Rate:	8,960	Btu/hp-hr
EU ID 14 Heat Rate:	11,138	Btu/hp-hr
EU ID 15 through 18 Heat Rate:	16,122	Btu/kW-hr
EU ID 31 Heat Rate:	11,277	Btu/hp-hr
Fuel Gas Heat Content:	1,017	Btu/scf
Boiler Horsepower Conversion:	33,479	Btu/hr/bhp
Diesel Fuel Heat Content:	137,000	Btu/gal

Grayling Platform

Fuel Gas H_2S Increase Project
Construction Permit Application

Attachment E - Demonstration of Compliance with State Emissions Standards

Hilcorp Alaska, LLC

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October 2023

Grayling Platform

Fuel Gas H_2S Increase Project

Construction Permit Application

Attachment E – Demonstration of Compliance with State Emissions Standards

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This document has been prepared by SLR International Corporation (SLR). The material and data in this report were prepared under the supervision and direction of the undersigned.

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Table of Contents

E1. Demonstration of Compliance with State Emissions Standards E1-1
E1.1 Visible Emissions Standard- 18 AAC 50.055(a)(1) E1-1
E1.2 Particulate Matter Emissions Standard – 18 AAC 50.055(b)(1) E1-1
E1.3 Sulfur Compound (SO_2) Emissions Standard – 18 AAC 50.055(c) E1-2

E1. Demonstration of Compliance with State Emissions Standards

E1.1 Visible Emissions Standard- 18 AAC 50.055(a)(1)

18 AAC 50.055(a)(1) applies to all fuel-burning equipment and states that visible emissions, excluding condensed water vapor, may not reduce visibility through the exhaust effluent by more than 20 percent averaged over any 6 consecutive minutes.

Visible emissions, excluding condensed water vapor, emitted from the gas-fired Grayling Platform emissions units affected by the project, will comply with the visible emissions standard based on exclusive combustion of natural gas.

E1.2 Particulate Matter Emissions Standard – 18 AAC 50.055(b)(1)

18 AAC 50.055(b)(1) applies to all fuel-burning equipment and states that particulate matter (PM) emissions may not exceed 0.05 gr/dscf of exhaust averaged over 3 hours.

Turbines

Compliance with the PM standard for turbines associated with an increase in the fuel gas H_2S content is demonstrated using the following equation:

$$\mathrm{PM}\left(\frac{\mathrm{gr}}{\mathrm{dscf}}\right)=\frac{\mathrm{EIPM}\left[\frac{\mathrm{lb\ PM}}{\mathrm{MMBtu_{HHV}}}\right]*\left(\frac{7{,}000\ \mathrm{gr}}{\mathrm{lb}}\right)}{\mathrm{F_d}\left[\frac{\mathrm{dscf}}{\mathrm{MMBtu}}\right]*\left(\frac{20.9}{20.9\text{-}\%\mathrm{O_2}}\right)}$$

where:

EIPM is the PM emissions factor from AP-42 Table 3.1-2a = 0.0066 lb/MMBtu, higher heating value (HHV).

F_d is the calculated volume of dry combustion products per unit of heat content for gas at stoichiometric conditions (0% O_2) based on the Grayling Platform comingled gas composition and higher heating value (dscf/MMBtu) = 8,710 dscf/MMBtu (Method 19, Equation 19-13).

$\%O_2$ is the percent oxygen on a dry basis in the turbine exhaust = 15.0%

$$\mathrm{PM}\left(\frac{\mathrm{gr}}{\mathrm{dscf}}\right)=\frac{0.0066*7{,}000}{8{,}710*\left(\frac{20.9}{20.9\text{-}15.0}\right)}=0.001\ \frac{\mathrm{gr}}{\mathrm{dscf}}$$

Heaters

Compliance with the PM standard for heaters associated with an increase in the fuel gas H_2S content is demonstrated using the following equation:

$$\mathrm{PM}\left(\frac{\mathrm{gr}}{\mathrm{dscf}}\right)=\frac{\mathrm{EIPM}\left[\frac{\mathrm{lb\ PM}}{\mathrm{MMBtu_{HHV}}}\right]*\left(\frac{7{,}000\ \mathrm{gr}}{\mathrm{lb}}\right)}{\mathrm{F_d}\left[\frac{\mathrm{dscf}}{\mathrm{MMBtu}}\right]*\left(\frac{20.9}{20.9\text{-}\%\mathrm{O_2}}\right)}$$

where:

EIPM is the PM emissions factor from AP-42 Table 1.4-2 = 7.6 lb/MMscf = 0.0075 lb/MMBtu, HHV.

F_d is the calculated volume of dry combustion products per unit of heat content for gas at stoichiometric conditions (0% O_2) based on the Grayling Platform comingled gas composition and higher heating value (dscf/MMBtu) = 8,710 dscf/MMBtu (Method 19, Equation 19-13).

%O_2 is the percent oxygen on a dry basis in the heater exhaust = 5.0%

$$\mathrm{PM}\left(\frac{\mathrm{gr}}{\mathrm{dscf}}\right)=\frac{0.0075 * 7{,}000}{8{,}710 * \left(\frac{20.9}{20.9\text{-}5.0}\right)} = 0.005\ \frac{\mathrm{gr}}{\mathrm{dscf}}$$

Flares

Compliance with the PM standard for the project flares is demonstrated using the following equation:

$$\mathrm{PM}\left(\frac{\mathrm{gr}}{\mathrm{dscf}}\right)=\mathrm{EIPM}\left[\frac{\mu\mathrm{g}}{\mathrm{L}_{\mathrm{Exh.}}}\right] * \mathrm{C} * \left(\frac{7{,}000\ \mathrm{gr}}{\mathrm{lb}}\right)$$

where:

EIPM is an emissions factor for lightly smoking flares based on a conservative interpretation of AP-42 Table 13.5-1 = 40 µg/L.

C is the factor to convert µg/L to lb/scf: = 6.2428 * e^{-8}

$$\mathrm{PM}\left(\frac{\mathrm{gr}}{\mathrm{dscf}}\right)= 40 * 6.2428e^{-8} * 7{,}000 = 0.017\ \frac{\mathrm{gr}}{\mathrm{dscf}}$$

The results of these equations demonstrate that the existing gas-fired fuel-burning equipment will comply with the 0.05 gr/dscf PM emissions standard set by 18 AAC 50.055(b)(1).

E1.3 Sulfur Compound (SO_2) Emissions Standard – 18 AAC 50.055(c)

18 AAC 50.055(c) applies to all fuel-burning equipment and states that sulfur compound emissions, expressed as SO_2, may not exceed 500 parts per million (ppm) averaged over 3 hours.

The proposed comingled fuel gas combusted by all significant fuel-gas fired emissions units on the platform will have an annual average H_2S content of 650 parts per million by volume (ppmv). However, the demonstration of compliance with the SO_2 standard is based on an H_2S concentration of 1,250 ppmv, which is the value used to derive the SO_2 emissions used in the ambient air quality modeling conducted for this application (see **Attachment F** of this application).

$$\mathrm{SO_2} = \frac{\mathrm{H_2S} * 1\left[\frac{\text{mole SO}_2}{\text{mole H}_2\text{S}}\right] * 385.3\left[\frac{\text{scf exh}}{\text{mole exh}}\right]}{\mathrm{F_d}\left[\frac{\mathrm{dscf}}{\mathrm{MMBtu}}\right] * \left(\frac{20.9}{20.9 - \%\mathrm{O_2}}\right) * \mathrm{HHV} * 379.6\left[\frac{\text{scf fuel}}{\text{mole fuel}}\right]} * 10^6$$

Turbines

H_2S is the maximum allowed hydrogen sulfide concentration in the fuel gas = 1,250 ppmv.

379.6 is the volume (standard cubic feet) of gas per mole of gas at 14.696 psia and 60°F.

385.3 is the volume (standard cubic feet) of exhaust per mole of exhaust at 14.696 psia and 68°F.

F_d is the calculated volume of dry combustion products per unit of heat content at stoichiometric conditions (0% O_2) based on the Grayling Platform comingled fuel gas composition and higher heating value = 8,710 dscf/MMBtu (Method 19, Equation 19-13).

$\%O_2$ is the percent oxygen in the turbine exhaust = 15.0%

HHV is the higher heating value of the fuel gas = 1,211 Btu/scf

$$SO_2 = \frac{1{,}250 \frac{\text{moles } H_2S}{\text{MM mole fuel}} * 1 \frac{\text{mole } SO_2}{\text{mole } H_2S} * 385.3 \frac{\text{scf exh}}{\text{mole exh}}}{8{,}710 \frac{\text{dscf}}{\text{MMBtu}} * \left(\frac{20.9}{20.9 - 15.0}\right) * 1{,}211 \frac{\text{Btu}}{\text{scf}} * 379.6 \frac{\text{scf fuel}}{\text{mole fuel}}} * 10^6 = 34.0 \text{ ppmv}$$

Flares

H_2S is the maximum allowed hydrogen sulfide concentration in the fuel gas = 1,250 ppmv

379.6 is the volume (standard cubic feet) of gas per mole of gas at 14.696 psia and 60°F.

385.3 is the volume (standard cubic feet) of exhaust per mole of exhaust at 14.696 psia and 68°F.

F_d is the calculated volume of dry combustion products per unit of heat content at stoichiometric conditions (0% O_2) based on the Grayling Platform comingled fuel gas composition and higher heating value = 8,710 dscf/MMBtu (Method 19, Equation 19-13).

$\%O_2$ is the percent oxygen in the flare exhaust = 0%

HHV is the higher heating value of the comingled gas = 1,211 Btu/scf

$$SO_2 = \frac{1{,}250 \frac{\text{moles } H_2S}{\text{MM mole fuel}} * 1 \frac{\text{mole } SO_2}{\text{mole } H_2S} * 385.3 \frac{\text{scf exh}}{\text{mole exh}}}{8{,}710 \frac{\text{dscf}}{\text{MMBtu}} * \left(\frac{20.9}{20.9 - 0}\right) * 1{,}211 \frac{\text{Btu}}{\text{scf fuel}} * 379.6 \frac{\text{scf fuel}}{\text{mole fuel}}} * 10^6 = 120.3 \text{ ppmv}$$

Heaters

H_2S is the maximum allowed hydrogen sulfide concentration in the fuel gas = 1,250 ppmv

379.6 is the volume (standard cubic feet) of gas per mole of gas at 14.696 psia and 60°F.

385.3 is the volume (standard cubic feet) of exhaust per mole of exhaust at 14.696 psia and 68°F.

F_d is the calculated volume of dry combustion products per unit of heat content at stoichiometric conditions (0% O_2) based on the Grayling Platform comingled fuel gas composition and higher heating value = 8,710 dscf/MMBtu (Method 19, Equation 19-13).

$\%O_2$ is the percent oxygen in the heater exhaust = 5.0%

HHV is the higher heating value of the comingled gas = 1,211 Btu/scf

$$SO_2 = \frac{1{,}250\ \frac{\text{moles } H_2S}{\text{MM mole fuel}} * 1\ \frac{\text{mole } SO_2}{\text{mole } H_2S} * 385.3\ \frac{\text{scf exh}}{\text{mole exh}}}{8{,}710\ \frac{\text{dscf}}{\text{MMBtu}}\ *\ \left(\frac{20.9}{20.9 - 5.0}\right) * 1{,}211 \frac{\text{Btu}}{\text{scf fuel}} * 379.6\ \frac{\text{scf fuel}}{\text{mole fuel}}} * 10^6 = 91.5 \text{ ppmv}$$

The calculation results demonstrate that the existing gas-fired fuel-burning equipment will comply with the 500 ppm sulfur compound (SO_2) emissions standard set by 18 AAC 50.055(c).

Grayling Platform

Fuel Gas H_2S Increase Project Construction Permit Application

Attachment F – Ambient Air Quality Impact Assessment

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SLR Project No.: 105.00874.20026

October 2023

Grayling Platform
Fuel Gas H_2S Increase Project
Construction Permit Application
Attachment F – Ambient Air Quality Impact Assessment

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Table of Contents

F1. Air Quality Impact Assessment Overview F1-1
F1.1 Dispersion Modeling Overview........ F1-1
F1.2 Modeling Methodology........ F1-1
F1.3 Meteorological Data........ F1-2
F1.3.1 Meteorological Dataset Construction F1-3
F1.4 Emissions Unit Parameters........ F1-5
F1.5 Model Receptors........ F1-9
F1.6 Ambient Monitoring Data F1-9
F1.6.1 Preconstruction Monitoring Requirements........ F1-9
F1.6.2 Background Concentration Values F1-10
F2. Quantitative Source Impact Analysis........ F2-1
F2.1 $PM_{2.5}$ (Total) Project-Only Impact Analysis – SIL........ F2-1
F2.2 SO_2 Cumulative Impact Analysis – AAQS........ F2-4
F2.3 SO_2 Cumulative Impact Analysis - PSD Class II and Class I Increment........ F2-12
F3. Qualitative Source Impact Analysis........ F3-1
F3.1 Understanding Regional Secondary $PM_{2.5}$ Formation........ F3-1
F3.1.1 $PM_{2.5}$ Formation Processes F3-1
F3.1.2 $PM_{2.5}$ Lifetimes F3-2
F3.1.3 Source and Distance Relationship on $PM_{2.5}$ Concentrations........ F3-3
F3.2 Reviewing Existing Data Important to Understanding Regional $PM_{2.5}$ Concentrations........ F3-3
F3.2.1 Existing $PM_{2.5}$ Concentrations F3-3
F3.2.2 Source and Regional Emissions........ F3-4
F3.3 Potential $PM_{2.5}$ Impacts F3-4
F4. Additional Impacts Analysis........ F4-1
F4.1 Growth Analysis........ F4-1
F4.2 Soil and Vegetation Impact Analysis........ F4-1
F4.2.1 Vegetation Impact F4-2
F4.2.2 Soils Impact........ F4-2
F4.3 Visibility F4-3
F5. Sources Impacting Class I Areas – Additional Requirements F5-1
F6. References........ F6-1

Tables

Table F1-1: Five Year Options Presented by ADEC and Hilcorp's Final Five-Year Surface Meteorological Dataset F1-2

Table F1-2: Meteorological Dataset Construction F1-3

Table F1-3: Monin-Obukhov Length to Stability Class for Overland Surface Roughness Values (Zo) F1-5

Table F1-4: Grayling Platform OCD Input Parameters F1-6

Table F1-5: Preconstruction Monitoring Values from Alaska LNG and Agrium Preapplication Monitoring Projects F1-10

Table F1-6: Background Monitoring Values from Alaska LNG Project F1-10

Table F2-1: SO_2 and $PM_{2.5}$ SILs, AAQS, and PSD Increments F2-1

Table F2-2: Comparison of Total (Direct and Secondary) $PM_{2.5}$ Impacts to the Class II SILs F2-2

Table F2-3: Comparison of Total (Direct and Secondary) $PM_{2.5}$ Impacts to the Class I SILs F2-3

Table F2-4: Grayling Platform Cumulative Impact Emission Rates F2-6

Table F2-5: Off-site Inventory and Model Inputs F2-7

Table F2-6: Cumulative SO_2 Modeling Results with a Source-Wide Fuel Gas H_2S Concentration of 1,250 ppmv F2-11

Table F2-7: Inventory of Point Sources Included in the Increment Analysis F2-15

Table F2-8: SO_2 PSD Class II Cumulative Increment Impact Analysis with a Source-Wide Fuel Gas H_2S Concentration of 1,250 ppmv F2-18

Table F2-9: SO_2 PSD Class I Cumulative Increment Impact Analysis with a Source-Wide Fuel Gas H_2S Concentration of 1,250 ppmv F2-18

Table F3-1: Regional Anthropogenic Emissions Near the Grayling Platform F3-5

Table F4-1: Vegetation Impact Analysis F4-2

Table F5-1: Project Q/d Analysis at the Tuxedni NWR F5-1

Figures

Figure F2-1: Existing Sources within ~50 km of the Grayling Platform Modeling Domain F2-13

F1. Air Quality Impact Assessment Overview

F1.1 Dispersion Modeling Overview

As required under this application for a PSD-major air quality construction permit for the Grayling Platform Fuel Gas H_2S Increase Project (i.e., the Project), Hilcorp Alaska, LLC (Hilcorp) is submitting this ambient air quality impact assessment (AQIA) of Grayling Platform emissions to demonstrate compliance with applicable National and Alaska Ambient Air Quality Standards (AAQS), Prevention of Significant Deterioration (PSD) Class II and Class I increment limits, and Air Quality Related Values (AQRVs). This AQIA addresses Project impacts and impacts from growth associated with the Project based on the current United States Environmental Protection Agency (USEPA)-approved models and methodologies.

The proposed increase of hydrogen sulfide (H_2S) on Grayling Platform is a major modification to an existing stationary source. The Project only results in an increase in sulfur dioxide (SO_2) emissions. That increase is large enough to exceed the PSD Significant Emission Rate for SO_2; therefore, that pollutant is subject to PSD review under 18 Alaska Administrative Code (AAC) 50.306. Because SO_2 is a precursor to particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), $PM_{2.5}$ emissions are also subject to the PSD AQIA-related demonstrations. As a result, this AQIA addresses the following PSD requirements for SO_2 and $PM_{2.5}$:

- **Source Impact Analysis** (40 C.F.R. 52.21(k)), the AQIA must demonstrate that the emissions increase from the Project will not cause an air pollution violation. This information is provided in Section F2 and Section F3.
- **Preapplication Impact Analysis** (40 C.F.R. 52.21(m)), the AQIA must include an analysis of ambient air quality in the Project area for each pollutant subject to review. This requirement is addressed in Section F1.5.
- **Additional Impacts Analysis** (40 C.F.R. 52.21(o)), the AQIA must include an analysis of the impairment to visibility, soils and vegetation that would occur because of the Project and general commercial, residential, industrial, and other growth associated with the Project. This requirement is addressed in Section F4.
- **Class I Impacts Analysis** (40 C.F.R. 52.21(p)), it is anticipated that the AQIA should include an analysis of the impacts from the Project on air quality related values in Federal Class I areas. This requirement is addressed in Section F5.

In accordance with 40 C.F.R. 52.21(l), the application is required to use an appropriate air quality model to estimate ambient air concentrations. This requirement is addressed in Section F1.2.

The required demonstrations and associated methodologies are described in subsequent sections. The results of the AQIA demonstrate that ambient impacts due to emissions from the Project will not interfere with the maintenance of the AAQS and will be below the PSD increments.

F1.2 Modeling Methodology

Hilcorp used the Offshore and Coastal Dispersion (OCD) model to predict direct Project SO_2 impacts. OCD requires meteorological data collected over land and over water, though the data over land is ignored if there are no receptors over land, which is the case for the largest and most critical part of the modeled domain. With approval from the Alaska Department of Environmental Conservation (ADEC), Hilcorp developed meteorological input datasets using existing buoy and weather stations in the upper Cook Inlet. Using this data, Hilcorp predicted cumulative SO_2 impacts, which includes impacts from nearby and non-modeled sources.

Increment modeling is discussed under Section F2.3. Applicable sources were included based on the size of the modeling domain. Hilcorp developed a strategy based on source emissions combined with the addition of background concentrations for including or excluding sources while still accounting for the impacts from all sources.

Finally, because SO_2 is a precursor to $PM_{2.5}$, potential direct and secondarily formed $PM_{2.5}$ impacts must be addressed by this AQIA. These impacts are addressed quantitatively using a combination of MERPs and dispersion modeling in Section F2.1 and qualitatively in Section F3.

F1.3 Meteorological Data

USEPA's Revisions to the Guideline on Air Quality Models (USEPA 2017) (Guideline) outlines use of appropriate meteorological data for modeling. In summary, a Permittee may use either one year of site-specific data, usually collected on or near the site, or five years of data from any representative weather stations, including airport Automated Surface Observing System (ASOS) instruments or offshore buoys.

The OCD model requires data from both overland- and overwater-based stations. Although as noted, the overland data is only used if land exists and is flagged as such within the modeling domain. While there are small parts of the modeling domain over land, those areas are located far from the location of maximum model-predicted impacts and it is not important to account for the effects of the land-sea transition on model predicted impacts since they would be small, if they even occurred. Therefore, no overland receptors were identified. Regardless, overland meteorological data was still processed and generated for the analysis.

Hilcorp proposed to ADEC to use a non-consecutive meteorological dataset built from data collected at existing stations. ADEC accepted the proposal on April 1, 2020, with the use of either of the non-consecutive five-year datasets shown in **Table F1-1**, with a slight preference to Option 2. ADEC proposed these options due to the completeness of the National Oceanic and Atmospheric Association's (NOAA) Nikiski NKTA2 National Ocean Service (NOS) data station. The options presented cover calendar quarters with the required 90% or better data capture completeness. Hilcorp modified the years slightly due to incomplete periods of the NKTA2 data and lack of an adequate substitute. The adjusted period is italicized in **Table F1-1**.

Table F1-1: Five Year Options Presented by ADEC and Hilcorp's Final Five-Year Surface Meteorological Dataset

Year	Option 1: Calendar Years	Option 2: Non-Calendar Years	Final Multi-Year Dataset
1	Q1 2012 – Q4 2012	Q3 2012 – Q2 2013	Q3 2012 – Q2 2013
2	Q1 2013 – Q4 2013	Q3 2013 – Q2 2014	Q3 2013 – Q2 2014
3	Q1 2014 – Q4 2014	Q3 2014 – Q2 2015	Q3 2014 – Q2 2015
4	Q1 2018 – Q4 2018	Q1 2018 – Q4 2018	*Q2 2017 – Q1 2018*
5	Q1 2019 – Q4 2019	Q1 2019 – Q4 2019	Q1 2019 – Q4 2019

F1.3.1 Meteorological Dataset Construction

OCD has minimum data requirements for both the overland and overwater inputs to the model. The model requires complete data without missing values for the following parameters: overwater air temperature; sea surface temperature; overwater mixing height; and overwater humidity. The remaining data can have missing values. **Table F1-2** outlines the requirements and the actual data used to construct the multi-year dataset. The individual pieces that comprised the complete meteorological dataset are discussed below.

F1.3.1.1 Overwater Air Temperature and Sea Surface Temperature

Overwater air temperature and sea surface temperature are the two most important parameters for OCD and complete data is required for the model. ADEC approved the use of the NKTA2 NOS station at Nikiski, which is located adjacent to the coast 20 kilometers (km) from the Project area. The station collects simultaneous sea surface temperature and overwater air temperature data.

The NKTA2 NOS station is subject to extreme weather, so large portions of data are often missing. This is the reason for the discontinuous datasets proposed in **Table F1-1**, and why Hilcorp modified Year 4. It was discovered during the processing of the raw data that while overwater temperature was recorded for 2018, much of the corresponding sea surface temperature measurements were missing.

The quarterly data for NKTA2 in Hilcorp's final five-year dataset is over 90% complete. OCD requires 100% complete data for overwater and sea surface temperature, so minimal substitution was required. When looking for an adequate substitute, Hilcorp considered the following:

- As a first order substitute, use a nearby station that has simultaneous overwater and sea surface temperature.
- As a second order substitute, use data from a nearby buoy or land-based station.

Table F1-2: Meteorological Dataset Construction

Parameters		Data Used
Land	Wind Speed	Kenai Airport
	Wind Direction	
	Land-Based Temperature	
	Land-Based Mixing Height	AERMET-processed Kenai Airport
	Stability	
	Upper Air	Anchorage FSL (required to run AERMET)
Water	Overwater Air Temperature	NKTA2 (Nikiski) and ANTA2 (Anchorage), with FILA2 (Flat Island) C-MAN substitutions as needed
	Overwater Humidity	Kenai Airport with HMRA2 (Homer Spit) substitutions
	Sea Surface Temperature	NKTA2 (Nikiski) and ANTA2 (Anchorage) with Seldovia substitutions as needed
	Overwater Mixing Height	Manual Calculation

To satisfy the substitution algorithm, Hilcorp used data from an NOS station near Anchorage, ANTA2. For most years, that data completed the overwater and sea surface temperature requirements. For any other missing values, sea surface temperature values were substituted with the Seldovia buoy, OVIA2, and the overwater temperature values were from the Flat Island C-MAN station, FILA2.

F1.3.1.2 AERMET

AERMET version 19191 and the pre-processor AERMINUTE version 15272 were used to process Kenai Airport (PAEN) ASOS data for land-based temperature, wind direction and speed, mixing height, and as a substitute for overwater humidity. While AERMET version 19191 is not current, the overland surface meteorological input data developed with it is minimally used by the OCD model for this analysis which includes limited overland receptors located far from the platform. Therefore, relying on an older version of AERMET has no bearing on this analysis from that perspective. However, the mixing height data generated by AERMET is being used to develop overwater mixing heights. Regardless, any differences in the mixing heights calculated with the different model versions is expected to be inconsequential. This is because changes between version 19191 and 22112 related to mixing height calculations were limited to including a data quality check in a smoothing algorithm and did not include any regulatory formulation updates, or enhancements. Furthermore, the AERMET-generated mixing heights are further processed into overwater mixing heights. Between this post-processing and any small changes that may result from model revisions, predicted impacts should not be sensitive to model version. Hilcorp used the following for AERMET processing:

- Stage input file construction based on the accepted Kenai meteorological dataset found online at ADEC’s *AERMOD Meteorological Data* website. This includes the geophysical parameters.
- Anchorage Upper Air soundings were used to satisfy the upper air requirement.
- AERMINUTE was used to process the 1-minute ASOS data at PAEN to better characterize winds.

The following AERMET-processed surface data from Kenai were used: wind speed, wind direction, air temperature, mixing height, and atmospheric stability. Further discussion about mixing heights and atmospheric stability is provided below.

F1.3.1.3 Land-Based Mixing Height

Mechanical mixing height is the mixing height due to wind shear near the surface. Convective mixing height is the mixing due to convection, or the heating of the surface to produce thermals. During the day, convective mixing begins to overtake mechanical mixing as the land heats up. Since OCD does not differentiate between convective or mechanical mixing height, Hilcorp used the larger of the two produced by AERMET as the representative mixing height.

F1.3.1.4 Overland Atmospheric Stability

OCD requires the stability to be categorized using Pasquill-Gifford (PG) stability classes A through F. AERMET does not provide output PG stability classes but provides hourly surface roughness and Monin-Obukhov length. Using Table 2-5 from the 1989 volume of the *OCD User’s Guide*, the Monin-Obukhov length can be converted to PG stability class using the surface roughness length as shown in **Table F1-3**. Hilcorp algorithmically did this conversion based on the surface roughness length for each hour and the noted breakpoints in **Table F1-3**.

Table F1-3: Monin-Obukhov Length to Stability Class for Overland Surface Roughness Values (Zo)

Transition Point	Zo = 0.1 m	Zo = 0.01 m	Zo = 0.002 m
	Value of L (m)	Value of L (m)	Value of L (m)
A/B	-10.5	-7.7	-6.7
B/C	-28.6	-16.7	-12.5
C/D	-125	-50	-33.3
D/E	125	50	33.3
E/F	28.6	14.3	9.1

F1.3.1.5 Overwater Mixing Height

For overwater mixing height, Hilcorp used the following algorithm based on Hsu (1997):

MH(sea) = MH(land) – 123*[T(land) – T(sea)]

where:

- MH(sea) = overwater mixing height
- MH(land) = overland mixing height
- T(land) = temperature over land
- T(sea) = temperature over water

This approach was used in the Northeast Gateway Project (United States Coast Guard 2006). To account for all possible scenarios, the following calculations were also used to ensure full data capture for overwater mixing height:

- If T(land) – T(sea) is negative, MH(sea) = MH(land).
- If MH(sea) is negative or any of the input values are missing, MH(sea) = 1.

F1.4 Emissions Unit Parameters

OCD characterizes the emissions units both on a planar coordinate system as well as relative to each deck of the platform. The emissions units at Grayling Platform are spread across five decks, and thus, the locational input parameters include a reference to a base deck relative to mean sea level (MSL). The base elevation also dictates the stack height and building heights for downwash calculations built into the model. Additionally, OCD requires a building width for downwash, which is the width of the platform on its narrowest side.

Table F1-4 shows the required input parameters for both the affected emissions units and unmodified emissions units at Grayling Platform. For the cumulative AAQS analysis only, both the Kuukpik V drill rig and a resupply vessel tied up to the platform are included (sources K1-K7 and Resupply).

Table F1-4: Grayling Platform OCD Input Parameters

EU ID/ Model ID	Make/Model	Relative To…	X-Coord (m) [1]	Y-Coord (m) [1]	Bldg Top (m)	Stack Height (m)	Emiss Temp (K)	Stack Dia (m)	Exit Velocity (m/s)	Stack Angle [3]	Deck Elev (m)	Deck Width (m)
Gas-Fired Grayling Platform Emissions Units Affected by the H_2S Increase												
1	Solar Centaur T4500	Production Deck	2.54	-24.4	25.8	3.25	783	0.914	20.0	90	17.2	34.7
3	Solar Centaur T4500	Production Deck	-20.7	-20.0	25.8	3.25	783	0.914	20.0	90	17.2	34.7
4	Solar Centaur T4500	Sub Deck	-12.5	-25.3	25.8	11.8	783	0.914	20.0	0	17.2	34.7
14	Solar Saturn T1200	Prod. Deck Mezzanine	-14.0	4.56	31.5	0.136	720	0.457	21.9	0	11.4	34.7
15	Solar Saturn T1200	Production Deck	21.7	-8.08	22.3	0.691	720	0.762	11.8	90	20.6	34.7
16	Solar Saturn T1200	Prod. Deck Mezzanine	21.7	-8.08	25.8	4.17	720	0.762	11.8	90	17.2	34.7
17	Solar Saturn T1200	Production Deck	21.7	-2.74	22.3	0.691	720	0.762	11.8	90	20.6	34.7
18	Solar Saturn T1200	Sub Deck	21.7	-2.74	25.8	4.17	720	0.762	11.8	90	17.2	34.7
19	Continental Boiler	Sub Deck	0.39	-12.0	31.5	3.80	500	0.356	23.8	0	11.4	34.7
20	Continental Boiler	Production Deck	-3.26	-12.0	31.5	3.80	500	0.356	23.8	0	11.4	34.7

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Table F1-4 (Continued): Grayling Platform OCD Input Parameters

EU ID/ Model ID	Make/Model	Relative To…	X-Coord (m) [1]	Y-Coord (m) [1]	Bldg Top (m)	Stack height (m)	Emiss Temp (K)	Stack Dia (m)	Exit Velocity (m/s)	Stack Angle [3]	Deck Elev (m)	Deck Width (m)
Gas-Fired Grayling Platform Emissions Units Affected by the H_2S Increase (continued)												
28	Flare (South)	Production Deck	-0.91	-40.0	25.8	16.7	1273	1.53	20.0	0	17.2	34.7
29	Flare (SW)	Drill Deck	-40.0	-40.0	25.8	16.7	1273	1.53	20.0	0	17.2	34.7
31	Solar Taurus 60	Sub Deck	16.7	29.8	18.7	9.52	783	1.23	11.0	135	24.3	34.7
Grayling Platform Emissions Units Unaffected by the H_2S Increase												
24	Cat 3406 Engine	Drill Deck	20.3	1.63	18.7	9.52	662	0.102	159	0	24.3	34.7
25	Cat 3208 Engine	Drill Deck	-20.9	-0.522	18.7	9.52	728	0.102	93.9	0	24.3	34.7
26a	Detroit Diesel Series 60	Production Deck	25.5	4.04	25.8	53.9	800	0.127	50.0	90	17.2	34.7
27	Cat D-330C Engine	Sub-Sub Deck	-12.2	3.33	34.8	7.07	783	0.102	36.6	0	8.2	34.7
Kuukpik V Transportable Drill Rig												
K1 [2]	Hydraulic Power Unit	Drill Deck	17.5	-3.53	34.8	33.2	658	0.153	64.3	0	24.3	34.7
			17.5	-4.78	34.8	33.2	658	0.153	64.3	0	24.3	34.7
K2 [2]	Hydraulic Power Unit	Drill Deck	17.5	-6.03	34.8	33.2	658	0.153	64.3	0	24.3	34.7
			17.5	-7.28	34.8	33.2	658	0.153	64.3	0	24.3	34.7

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Table F1-4 (Continued): Grayling Platform OCD Input Parameters

EU ID/ Model ID	Make/Model	Relative To…	X-Coord (m) [1]	Y-Coord (m) [1]	Bldg Top (m)	Stack height (m)	Emiss Temp (K)	Stack Dia (m)	Exit Velocity (m/s)	Stack Angle [3]	Deck Elev (m)	Deck Width (m)
Kuukpik V Transportable Drill Rig (continued)												
K3	Light Plant Generator	Drill Deck	14.6	-17.7	34.8	25.0	780	0.153	82.8	45	24.3	34.7
K4	Light Plant Generator	Drill Deck	17.1	-17.7	34.8	25.0	780	0.153	82.8	45	24.3	34.7
K5	Portable Hydraulic Generator	Drill Deck	0.00	-17.7	34.8	28.0	728	0.076	39.7	0	24.3	34.7
K6	Boiler	Drill Deck	12.3	-17.7	34.8	25.9	550	0.305	0.001	0	24.3	34.7
K7	Boiler	Drill Deck	12.3	-15.2	34.8	25.9	550	0.305	0.001	0	24.3	34.7
Platform Service Vessel												
RESUPPLY	Resupply Ship	MSL	20.4	-21.0	14.5	15.2	700	0.650	40.5	0	0	34.1

[1] X-Y Coordinates are relative to platform center.

[2] EU IDs K1 and K2 have dual stacks per emissions unit.

[3] Stack Angle: vertical = 0 degrees, horizontal = 90 degrees, and downward = 180 degrees.

F1.5 Model Receptors

The receptor grid is based on previous analyses done using OCD for Cook Inlet Platforms. Since platforms do not have a fence line, Hilcorp followed the standard approach followed for Cook Inlet offshore platforms and used an approximate 100-meter safety zone centered on the platform, with receptors placed at 10-degree increments. From there, the polar receptor rings are spaced at 50-meter intervals out to 500 meters (m). Each ring has receptors located at 10-degree increments. From 500 m to 1 km, Hilcorp continued to use the polar grid, but increased the ring spacing up to 100 m. The grid then switches to a cartesian grid with coarser spacing from 1 to 5 km at 500-m spacing, from 5 to 10 km at 1-km spacing, and then from 10 to 15 km at 2.5-km spacing.

F1.6 Ambient Monitoring Data

Ambient Monitoring data were used to satisfy both the PSD preconstruction monitoring requirements and the background requirements for the cumulative impact assessment.

F1.6.1 Preconstruction Monitoring Requirements

40 C.F.R. 52.21(m) requires a preapplication analysis of ambient air quality in the area to show that no violation of the AAQS exists prior to the modification. Hilcorp requested, and ADEC approved, the use of data collected at regional maximum impact locations to satisfy the preapplication monitoring requirement. Therefore, Hilcorp used the same preapplication data used to support the Alaska Gasline Development Corporation (AGDC) Alaska LNG Liquefaction Facility project construction permit application, i.e., data collected by the AGDC Alaska LNG ambient monitoring program station from September 1, 2018 to August 31, 2019 and by the Agrium Kenai Nitrogen Operation ambient monitoring program station from October 1, 2013 to September 30, 2014. There is no more recent data that has been collected in the Project impact area and very little growth has occurred that would drive the need to consider more current data.

The stations for both programs were located near each other at predicted maximum impact locations within one of the most densely industrialized areas of this part of the Cook Inlet. With the bimodal wind directions in Cook Inlet, the data from these two stations were collected upwind/ downwind of several large industrial sources such as the Tesoro Kenai Refinery, the Nikiski Combined Cycle Plant, and the Bernice Lake Power Plant, in addition to several smaller facilities supporting both onshore and offshore oil and gas development. Additionally, the stations were located adjacent to the Kenai Spur Highway, and near a narrow point in the Cook Inlet that concentrates ocean-going and regional vessel traffic. Because of this, the data collected by these two stations are the most likely to show if there are regional attainment issues; thereby satisfying preapplication analysis requirements for the Grayling Platform permit application.

The applicable pollutants and concentrations monitored at the Alaska LNG and Agrium preapplication monitoring program stations are listed in **Table F1-5**. A review of this data shows that the area is in attainment with the AAQS consistent with model predictions in this area.

Table F1-5: Preconstruction Monitoring Values from Alaska LNG and Agrium Preapplication Monitoring Projects

Pollutant [1]	Averaging Period	Concentration ($\mu g/m^3$)	AAQS ($\mu g/m^3$)
SO_2	Annual	0.0 [2]	80
	24-hour	0.0 [2]	365
	3-hour	0.0 [2]	1,300
	1-hour	3.9	196
$PM_{2.5}$	Annual	3.6	12
	24-hour	8.0	35

[1] SO_2 concentrations were measured by the AGDC Alaska LNG ambient monitoring program.
$PM_{2.5}$ concentrations were measured by the Agrium Kenai Nitrogen Operations ambient monitoring program.

[2] Measured concentration was zero $\mu g/m^3$.

F1.6.2 Background Concentration Values

According to the Guideline, background concentrations should be representative of the following in the vicinity of the source under consideration: 1) natural sources, 2) nearby sources other than those modeled explicitly, and 3) unidentified sources. Ambient air quality data that can be demonstrated to meet these criteria and are of PSD-quality are acceptable as the basis for developing background concentrations to support modeling demonstrations.

Background concentrations were developed using data collected as part of the Alaska LNG Project Air Quality Monitoring Program located in Nikiski, Alaska. The primary objective of the monitoring program was to collect PSD-quality ambient air quality data that are representative of the Nikiski area to support future regional air quality compliance demonstrations and ozone (O_3) preconstruction monitoring requirements. Data collected at this location include impacts from non-modeled sources such as mobile sources (onshore, offshore, and airborne), regional sources ranging from industrial facilities to residential heating, and other unidentified natural and international sources.

Table F1-6 summarizes the full year of data available from the Alaska LNG Nikiski site spanning January 1, 2015 – December 31, 2015.

Table F1-6: Background Monitoring Values from Alaska LNG Project

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)	AAQS ($\mu g/m^3$)
SO_2	Annual	0 [1]	80
	24-hour	0 [1]	365
	3-hour	0 [1]	1,300
	1-hour	4.3	196
$PM_{2.5}$	Annual	3.7	12
	24-hour	12.0	35

[1] Measured concentration was zero $\mu g/m^3$.

F2. Quantitative Source Impact Analysis

Impacts from the Project net increase in emissions do not exceed the $PM_{2.5}$ Class I and Class II Significant Impact Levels (SILs) but do exceed the SO_2 Significant Impact Levels (SILs); therefore, quantitative cumulative AAQS and cumulative PSD Class I and Class II increment analyses have been completed for SO_2 only. **Table F2-1** lists the SO_2 and $PM_{2.5}$ SIL thresholds, the AAQS, and the PSD Class II and Class I increment limits.

Table F2-1: SO_2 and $PM_{2.5}$ SILs, AAQS, and PSD Increments

Pollutant	Averaging Period	PSD Class II SIL (µg/m^3)	PSD Class I SIL (µg/m^3)	AAQS (µg/m^3)	PSD Class II Increment (µg/m^3)	PSD Class I Increment (µg/m^3)
SO_2	Annual	1	0.1	80 [1]	20 [1]	2 [1]
	24-hour	5	0.2	365 [2]	91 [2]	5 [2]
	3-hour	25	1.0	1,300 [2]	512 [2]	25 [2]
	1-hour	7.8	N/A	196 [3]	N/A	N/A
$PM_{2.5}$	Annual	0.2	0.05	12.5 [4]	4 [1]	1 [1]
	24-hour	1.2	0.27	35 [5]	9 [2]	2 [2]

[1] Not to be exceeded.

[2] Not to be exceeded more than once each year.

[3] Three-year average of the annual, 99th percentile, daily maximum, one-hour averages.

[4] Three-year average of the annual average.

[5] Three-year average of the annual, 98th percentile, 24-hour averages.

F2.1 $PM_{2.5}$ (Total) Project-Only Impact Analysis – SIL

The project-only source impact analysis conducted for $PM_{2.5}$ shows that Project impacts are below the $PM_{2.5}$ SILs, which demonstrates that the Project will not cause or contribute to a violation of the $PM_{2.5}$ AAQS or PSD Class II and Class I increments.

USEPA established $PM_{2.5}$ SILs and made recommendations for applying the SILs (USEPA 2018). USEPA recommends SILs be applied on a case-by-case basis recognizing that the use of a SIL may not be appropriate when a substantial portion of any National Ambient Air Quality Standard (NAAQS) or increment is known to be consumed. To guard against the improper use of the SILs, USEPA recommends that SILs be used when it can be established that the difference between background concentrations and the NAAQS in a particular area is greater than the SIL values, which is the case for the area in proximity to the Project.

The Grayling platform is located offshore in a low-density source environment with only four sources located within 10 km, and very little new source development and mobile source activity compared to even lightly industrialized areas. As such, it is unlikely that the cumulative effect of de minimis increases from regional sources will accumulate at a location and contribute to a violation of an applicable standard. Furthermore, **Table F1-5** and **Table F1-6** show existing $PM_{2.5}$ ambient background concentrations are less than 35 percent of the AAQS. Because of a low probability for overlapping impacts between sources and the low measured background pollutant concentrations, it is acceptable to rely on the SILs to demonstrate this project will not cause or contribute to a violation of the $PM_{2.5}$ AAQS and PSD Increments.

Comparing impacts to the SILs is more complicated for $PM_{2.5}$ because of the role of precursor emissions. This is described in USEPA 2022 which recommends following a procedure described in USEPA 2019 to account for precursors and conduct the source impact analysis for this pollutant. Following that guidance, Project total NO_x, and SO_2 emissions are scaled by the impacts predicted by USEPA from representative sources through the application of Modeled Emission Rates for Precursors (MERPs) to estimate secondarily formed $PM_{2.5}$ impacts. Estimated $PM_{2.5}$ secondary impacts are added to direct impacts predicted with a dispersion model and then compared to applicable thresholds.

Following UESPA 2019, comparing impacts to the SILs is done as a percentage of the SILs when conducting a near field analysis or using predicted mass concentrations in ambient air when conducting a far field analysis. The results of applying this approach to Class II and Class I areas for this project are shown in **Table F2-2** and **Table F2-3**, respectively. These show that Project $PM_{2.5}$ impacts are below the SILs thereby demonstrating that the Project will not cause or contribute to a violation of the $PM_{2.5}$ AAQS or the PSD Class I and II Increments. Details supporting the analysis and this conclusion are provided in the following paragraphs.

Table F2-2: Comparison of Total (Direct and Secondary) $PM_{2.5}$ Impacts to the Class II SILs

Pollutant and Averaging Period	Direct Impact		Precursor Pollutant	Project Emissions Increase [1] (tpy)	MERP (tpy) [2]	Secondary Impact (% of SIL) [3]	Total Impact (% of SIL) [3]
	(μg/m^3)	(% of SIL)					
24-hour $PM_{2.5}$	0 [4]	0	NO_x	0	3,003 [5]	8.1	8.1
			SO_2	70.1	865 [6]		
Annual $PM_{2.5}$	0 [4]	0	NO_x	0	7,942 [5]	1.4	1.4
			SO_2	70.1	5,136 [6]		

[1] Project net emissions increase as defined in 40 CFR 52.21(b)(3) and documented in **Attachment B** of the application.

[2] Lowest (most conservative) illustrative MERP from among all sources located in the northwest climate zone on a pollutant-by-pollutant basis.

[3] Impacts are predicted as a percentage of the SIL following USEPA procedures (USEPA 2019). Therefore, a total impact of less than 100% demonstrates compliance with the standard.

[4] The Project has no net increase in direct $PM_{2.5}$ emissions; therefore, no direct $PM_{2.5}$ impacts.

[5] Based on a hypothetical source modeled in Morrow County, Oregon.

[6] Based on a hypothetical source modeled in Klamath County, Oregon.

Table F2-3: Comparison of Total (Direct and Secondary) $PM_{2.5}$ Impacts to the Class I SILs

Pollutant and Averaging Period	Direct Impact (μg/m^3)	Precursor Pollutant	Project Emissions Increase [1] (tpy)	MERP Emissions Scalar (g/s/ 500 tpy) [2]	Secondary Impact (μg/m^3)	Total Impact (μg/m^3)	Class I SIL (μg/m^3)
24-hour $PM_{2.5}$	0 [3]	NO_x	0	0.09665 [4]	0.023	0.023	0.27
		SO_2	70.1	0.1624 [4]			
Annual $PM_{2.5}$	0 [3]	NO_x	0	0.004781 [5]	0.0007	0.0007	0.05
		SO_2	70.1	0.005237 [5]			

[1] Project net emissions increase as defined in 40 CFR 52.21(b)(3) and documented in **Attachment B** of the application.

[2] Highest (most conservative) secondary impact predicted at 80 km from a source with emissions of 500 tpy from among all sources located in the northwest climate zone on a pollutant-by-pollutant basis. The nearest Class I area is located 90 km from the Project.

[3] The Project has no net increase in direct $PM_{2.5}$ emissions; therefore, no direct $PM_{2.5}$ impacts.

[4] Based on a hypothetical source modeled in Morrow County, Oregon.

[5] Based on a hypothetical source modeled in Skagit County, Washington

Following USEPA guidance, the impact resulting from secondarily formed $PM_{2.5}$ is determined by scaling the secondary impact predicted from a representative source by the ratio of precursor emissions from the source under review to those from the representative source (USEPA 2019). USEPA recommends doing this as a percentage of the SILs using representative MERPs when predicting Class II impacts and as a concentration when predicting Class I impacts. As such, the approach used to select the representative source is done differently in each case.

For the Class II impacts analysis, based on data from the USEPA MERPs View Qlik website[1], the source with the lowest MERP from among all sources irrespective of location within the northwest climate zone was selected to represent the impacts from the Project. The northwest climate zone was selected because pollutant transport in this climate zone will be the most representative of transport conditions in the Project impact area because 1) the zone contains similar maritime and transitional climates, 2) sources in this zone are similarly exposed to the ocean and topography, and 3) sources in this zone are exposed to similar maritime weather systems and air masses. Relying on the worst-case MERP from among all sources in this climate zone obviates the need to evaluate MERPs based on other source specific characteristics such as stack height, and proximity to terrain and urban areas. This simplification also obviates the need for a close examination of source specific emissions characteristics when selecting a MERP.

Like the Class II impacts analysis, the Class I impacts analysis relied on predicted impacts from a source located within the northwest climate zone with the highest predicted impact from secondary particulate formation at 80 km and 500 tons per year (tpy) of precursor emissions. The USEPA MERPs View Qlik website provides modeled impacts predicted at distances ranging from 20 to 300 km in 20 km increments and source precursor emissions of 500, 1,000, and 3,000 tpy. 80 km was selected because this distance is similar to the distance from the

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[1] https://www.epa.gov/scram/merps-view-qlik

Project to the nearest Class I area and a 500 tpy emission rate was selected because it is the same order of magnitude as Project emissions.

For both the Class I and Class II impacts analysis, it was not necessary to predict impacts from direct $PM_{2.5}$ emissions because there is no net $PM_{2.5}$ emissions increase from the Project.

F2.2 SO_2 Cumulative Impact Analysis – AAQS

The cumulative impact analysis conducted to demonstrate source impacts are below applicable AAQS accounts for impacts from all on-site emissions units and off-site sources. There are several small, diesel-fired emissions units on Grayling Platform as well as the possibility of having the Kuukpik V transportable drill rig onsite. Both sources of emissions are included in the AAQS cumulative analysis. ADEC also requires predicting impacts from the service vessels while they are tied to the platform. For all applications that have required modeling in Cook Inlet, Hilcorp has characterized the service vessel as follows:

- Vessel engines have a combined horsepower (hp) of 9,395 hp, simulated as a single stack.
- Vessel is tied to the platform for no more than 3 hours a day.
- Vessel visits the platform for no more than 720 hours per year.
- Vessel is in the worst-case location – southeast leg of platform according to previous analyses.

Aside from modeling existing platform emissions units and the service vessels, impacts must be predicted from nearby sources using modeling. Nearby sources are defined as those that have the potential to produce a significant concentration gradient in the impact area of the Grayling Platform. Impacts from all other non-modeled sources are included by adding a representative background concentration to predicted impacts. Background concentrations are from the Alaska LNG monitoring station discussed under Section F1.6.

Off-site sources warrant additional discussion because while the Guideline recommends that off-site impacts be included based on “concentration gradient”, it is silent on a specific method for what constitutes a significant concentration gradient. Therefore, off-site sources have been included based on the following criteria:

- Proximity to the platform
- Existing actual emissions
- Dominant wind directions

There are numerous platforms and onshore sources within 50 km of the Grayling Platform. However, those that will likely have the potential to produce a significant concentration gradient in the Project impact area are likely to be upwind of the platform. Cook Inlet experiences a bimodal wind pattern, so only off-site sources directly upwind were included in the analysis. These include Steelhead, Dolly Varden, and King Salmon Platforms. Additionally, these platforms have higher potential H_2S than other distant platforms that use near pipeline-quality gas.

To simulate these platforms in the model, Hilcorp characterized them as a single point source using an aggregate emission rate based on the potential emissions or as individual point sources using actual average 2018/2019 emission rates, depending on the need for that level of refinement. As a result, King Salmon was simulated as a single point source and Dolly Varden as a collection of individual point sources. Regardless, all platforms were modeled with a service vessel attached to the worst-case leg of the platform.

The Steelhead Platform is also undergoing a project to increase the H_2S limit for some emissions units. The emissions units affected by this increase are included in the model using proposed potential emissions, while those unaffected use the 2018/2019 average of actual emissions. This is to accurately account for the contemporaneous permitting action at the Steelhead Platform.

There are two PSD-major sources proposed to be located in the Nikiski area that have either submitted a construction permit application and received a completeness determination but have not received a final permit, or recently obtained a permit but may not have started operation. Those are the AGDC Alaska LNG Liquefaction Facility and the Agrium Kenai Nitrogen Operations (KNO) facility. These sources have been included explicitly in the cumulative impact analysis since they have not been constructed and would not be represented in background concentrations.

Table F2-4 includes all the emission rates for the on-site emissions units and **Table F2-5** includes the emission rates and model inputs for the off-site inventory. Note that only short-term emission rates were used in the cumulative demonstration even though they have the potential to overestimate annual impacts for some platform emissions units.

The results of the cumulative impact analysis are shown in **Table F2-6**, which shows the increase in the H_2S limit will not cause or contribute to a violation of the AAQS. The 24-hour and 3-hour SO_2 concentrations are the highest-first high (H1H). The 1-hour SO_2 is the average of the five-year highest-fourth high (H4H) outputs.

Table F2-4: Grayling Platform Cumulative Impact Emission Rates

EU ID	Make/Model	Short-Term SO_2 ER (g/s)
Grayling Platform Emissions Units Affected by H_2S Increase		
1	Solar Centaur T4500	1.05
3	Solar Centaur T4500	1.05
4	Solar Centaur T4500	1.05
14	Solar Saturn T1200	0.319
15	Solar Saturn T1200	0.336
16	Solar Saturn T1200	0.336
17	Solar Saturn T1200	0.315
18	Solar Saturn T1200	0.336
19	Continental Boiler	0.194
20	Continental Boiler	0.194
28	Flare (South)	0.00597
29	Flare (Southwest)	0.00597
31	Solar Taurus 60	2.05
Grayling Platform Emissions Units Unaffected by H_2S Increase		
24	*Cat 3406 Engine*	0.151
25	Cat 3208 Engine	0.109
26a	Detroit Diesel Series 60	0.271
27	Cat D-330C Engine	0.042
Kuukpik V Transportable Drill Rig		
K1	Hydraulic Power Unit	0.001
		0.001
K2	Hydraulic Power Unit	0.001
		0.001
K3	Light Plant Generator	0.001
K4	Light Plant Generator	0.001
K5	Portable Hydraulic Generator	0.000
K6	Boiler	0.001
K7	Boiler	0.001
Platform Service Vessel		
RESUPPLY	Resupply Ship	0.002

Table F2-5: Off-site Inventory and Model Inputs

EU ID/ Model ID	Make/Model	Relative To…	X-Coord[1] (m)	Y-Coord[1] (m)	Short Term SO_2 ER (g/s)	Bldg Top (m)	Stack Hgt (m)	Emis Temp (K)	Stack Dia (m)	Exit Vel (m/s)	Stack Angle[2]	Deck Elev (m)	Deck Width (m)
Steelhead Platform													
S4	Solar Taurus 70 10302S Turbine	Pipe Rack - Lower Deck	588.41	-756.64	6.905	19.8	15.8	774.8	1.5	13.01	0	29.0	38.1
S5	Solar Taurus T 7000 Turbine	Pipe Rack - Lower Deck	584.31	-765.44	4.661	19.8	0.9	774.8	1.1	21.18	0	29.0	38.1
S14	Solar Saturn T 1200 Turbine	Pipe Rack - Lower Deck	590.76	-786.67	1.281	19.8	4.6	694.3	0.6	20.00	0	41.5	38.1
S15	Solar Saturn T 1200 Turbine	Pipe Rack - Lower Deck	590.76	-789.32	1.281	19.8	4.6	694.3	0.6	20.00	0	41.5	38.1
S12	HP/LP Flare/Pilot	Helipad Deck	598.00	-752.54	1.759	7.3	4.9	1273	1.2	39.07	0	29.0	38.1
S13	HP/LP Flare/Pilot	Helipad Deck	598.00	-785.53	1.759	7.3	4.9	1273	1.2	39.07	0	29.0	38.1
S1	Allison 501KB Turbine	Production Deck - Lower	584.20	-773.80	0.027	27.4	21.3	785.4	1.2	16.22	0	21.3	38.1
S2	Allison 501KB Turbine	Production Deck - Lower	584.20	-769.00	0.027	27.4	23.5	785.4	1.2	16.22	0	21.3	38.1
S3	Allison 501KB Turbine	Production Deck - Lower	584.20	-764.30	0.027	27.4	23.5	785.4	1.2	16.22	0	21.3	38.1
S6	Caterpillar D3516-TA	Production Deck - Upper	590.1	-745.9	0.013	21.9	3.0	527.6	0.3	18.29	90	26.8	38.1
S7	Caterpillar D399	Pipe Rack Level - Upper	566.7	-791.4	0.013	15.2	6.1	527.6	0.3	18.29	90	33.5	38.1
S8	Caterpillar C13	Helipad Deck	555.4	-740.9	0.080	7.3	5.8	747.0	0.3	10.28	0	41.5	38.1

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Table F2-5 (Continued): Off-site Inventory and Model Inputs

EU ID/ Model ID	Make/Model	Relative To…	X-Coord[1] (m)	Y-Coord[1] (m)	Short Term SO_2 ER (g/s)	Bldg Top (m)	Stack Hgt (m)	Emis Temp (K)	Stack Dia (m)	Exit Vel (m/s)	Stack Angle[2]	Deck Elev (m)	Deck Width (m)
Steelhead Platform (continued)													
S9	Caterpillar 3408 DITA	Helipad Deck	555.4	-797.2	0.029	7.3	5.8	755.4	0.3	19.88	0	41.5	38.1
S10	Detroit Diesel 12V71	Production Deck - Lower	522.0	-747.3	0.005	27.4	3.7	527.6	0.3	18.29	90	21.3	38.1
S11	Detroit Diesel 12V71	Production Deck - Lower	585.2	-791.8	0.005	27.4	3.7	527.6	0.3	18.29	90	21.3	38.1
S18	Caterpillar C9.3	Production Deck - Upper	558	-796	0.066	21.9	1.0	711.0	0.3	12.21	90	26.8	38.1
SRESUPPLY	Platform Resupply Ship	Mean Sea Level	578.4	-790	0.002	14.52	15.24	700	0.65	40.5	0	0	34.1
Dolly Vardon Platform													
DV1	Solar Saturn T-1200 Turbine	Sub-Sub-Deck	-1,157	-3,525	0.278	26.6	0.2	701	0.457	61.3	180	11.2	34.1
DV2	Solar Saturn T-1200 Turbine	Sub-Sub-Deck	-1,153	-3,525	0.278	26.6	0.2	701	0.457	61.3	180	11.2	34.1
DV5	Solar Saturn T-1200 Turbine	Sub-Sub-Deck	-1,176	-3,540	0.278	26.6	12.4	701	0.61	52.8	90	11.2	34.1
DV6	Solar Saturn T-1200 Turbine	Sub-Sub-Deck	-1,176	-3,541	0.278	26.6	12.4	701	0.61	52.8	90	11.2	34.1
DV7	Solar Saturn T-1200 Turbine	Sub-Sub-Deck	-1,176	-3,541	0.000	26.6	11.8	701	0.508	61.3	90	11.2	34.1
DV8	Solar Saturn T-1200 Turbine	Sub-Sub-Deck	-1,150	-3,525	0.278	26.6	2.0	598	0.457	61.3	180	11.2	34.1

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Table F2-5 (Continued): Off-site Inventory and Model Inputs

EU ID/ Model ID	Make/Model	Relative To…	X-Coord[1] (m)	Y-Coord[1] (m)	Short Term SO_2 ER (g/s)	Bldg Top (m)	Stack Hgt (m)	Emis Temp (K)	Stack Dia (m)	Exit Vel (m/s)	Stack Angle[2]	Deck Elev (m)	Deck Width (m)
Dolly Vardon Platform (Continued)													
DV9	Solar Saturn T-1200 Turbine	Sub-Sub-Deck	-1,132	-3,546	0.278	26.6	12.4	598	0.508	56.8	90	11.2	34.1
DV10	Solar Saturn T-1200 Turbine	Sub-Sub-Deck	-1,133	-3,544	0.444	26.6	12.4	598	0.508	53.2	90	11.2	34.1
DV12	Solar Centaur T-4500 Turbine	Sub-Sub-Deck	-1,174	-3,546	0.872	26.6	18	529	0.762	60.5	90	11.2	34.1
DV13	Solar Centaur T-5900 Turbine	Sub-Sub-Deck	-1,173	-3,571	0.102	26.6	16.84	710	1.22	13.0	90	11.2	34.1
DV16	Bryan Boiler	Sub-Sub-Deck	-1,171	-3,545	0.183	26.6	9.3	561	0.457	0.1	0	11.2	34.1
DV17	Bryan Boiler	Sub-Sub-Deck	-1,171	-3,547	0.183	26.6	9.3	561	0.457	0.1	0	11.2	34.1
DV20	Detroit Diesel 8V71 Engine (NE)	Sub-Sub-Deck	-1,132	-3,546	0.007	26.6	19.5	705	0.33	9.9	0	11.2	34.1
DV21	Detroit Diesel 8V71 Engine (SW)	Sub-Sub-Deck	-1,173	-3,549	0.007	26.6	19.5	705	0.33	9.9	0	11.2	34.1
DV22	Detroit Diesel Engine	Sub-Sub-Deck	-1,171	-3,549	0.009	26.6	0	728	0.203	54.1	180	11.2	34.1
DV23	Detroit Diesel Engine	Sub-Sub-Deck	-1,161	-3,552	0.009	26.6	0	741	0.203	59.9	180	11.2	34.1
DV24	Caterpillar 3306B Engine	Sub-Sub-Deck	-1,159	-3,559	0.005	26.6	25.22	713	0.127	66.3	0	11.2	34.1
DV20	Detroit Diesel 8V71 Engine (NE)	Sub-Sub-Deck	-1,132	-3,546	0.007	26.6	19.5	705	0.33	9.9	0	11.2	34.1

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Table F2-5 (Continued): Off-site Inventory and Model Inputs

EU ID/ Model ID	Make/Model	Relative To…	X-Coord[1] (m)	Y-Coord[1] (m)	Short Term SO_2 ER (g/s)	Bldg Top (m)	Stack Hgt (m)	Emis Temp (K)	Stack Dia (m)	Exit Vel (m/s)	Stack AngLE[2]	Deck Elev (m)	Deck Width (m)
Dolly Vardon Platform (continued)													
DV21	Detroit Diesel 8V71 Engine (SW)	Sub-Sub-Deck	-1,173	-3,549	0.007	26.6	19.5	705	0.33	9.9	0	11.2	34.1
DV22	Detroit Diesel Engine	Sub-Sub-Deck	-1,171	-3,549	0.009	26.6	0	728	0.203	54.1	180	11.2	34.1
DV23	Detroit Diesel Engine	Sub-Sub-Deck	-1,161	-3,552	0.009	26.6	0	741	0.203	59.9	180	11.2	34.1
DV24	Caterpillar 3306B Engine	Sub-Sub-Deck	-1,159	-3,559	0.005	26.6	25.22	713	0.127	66.3	0	11.2	34.1
DV25	Flare (SF/HP/LP) and Pilot	Sub-Sub-Deck	-1,191	-3,570	1.476	26.6	19.5	1273	1.53	20.0	0	11.2	34.1
DV26	Solar Taurus Turbine	Sub-Sub-Deck	-1,173	-3,535	0.114	26.6	16.84	783	1.22	15.2	90	11.2	34.1
DVRESUPPLY	Platform Resupply Ship	Mean Sea Level	-1,132	-3,568	0.002	14.52	15.24	700	0.65	40.5	0	0	34.1
King Salmon Platform													
KING	King Salmon Platform	-	428.7	3,050	16.2	9.2	6.70	777	1.07	2.1	0	13.9	33.5
Alaska LNG Liquefaction Facility													
AKLNG	AGDC AKLNG Liquefaction Facility	MSL	34,639	-37,053	0.175	10	7.6	777	1.02	52.1	0	50	36.6
Agrium Kenai Nitrogen Operations													
AGRIU	Agrium KNO	MSL	13,118	-18,140	0.413	10	7.6	777	1.02	52.1	0	50	36.6

[1] X-Y Coordinates are relative to platform center.

[2] Stack Angle: vertical = 0 degrees, horizontal = 90 degrees, and downward = 180 degrees.

Table F2-6: Cumulative SO_2 Modeling Results with a Source-Wide Fuel Gas H_2S Concentration of 1,250 ppmv

Pollutant	Averaging Period	Modeled Concentration (µg/m³)						Background (µg/m³)	Total (µg/m³)	AAQS (µg/m³)	% AAQS
		2012-2013	2013-2014	2014-2015	2017-2018	2019	Max. or Average [1]				
SO_2	Annual	14.4	13.8	15.2	14.4	13.6	14.4	0	14.4	80	19
	24-hour	83.5	78.3	63.5	77.6	80.1	83.5	0	83.5	365	23
	3-hour	150	133	148	158	150	158	0	158	1,300	12
	1-hour	169	184	177	177	182	178	4.3	182	196	93

[1] 1-hour SO_2 impacts only.

F2.3 SO_2 Cumulative Impact Analysis - PSD Class II and Class I Increment

A cumulative PSD Class I and Class II increment analysis was conducted for Grayling Platform that includes the Project and the impacts from all (mobile and stationary) increment consuming emissions. The determination of whether emissions consume or expand the increment is based on changes in actual emissions since the Minor Source Baseline Date. For SO_2 in the Cook Inlet Intrastate Air Quality Region, the Minor Source Baseline Date is October 12, 1979.

Conducting a comprehensive PSD increment consumption impact analysis based solely on model predicted impacts is very time consuming given the following considerations:

- Difficulty of determining actual emissions at the Minor Source Baseline Date for all sources (major, minor, stationary, mobile, etc.).
- Difficulty in modeling the proper facility physical configuration at the Minor Source Baseline Date for all sources.
- Difficulty in determining how the emissions and facility configurations have changed over time.

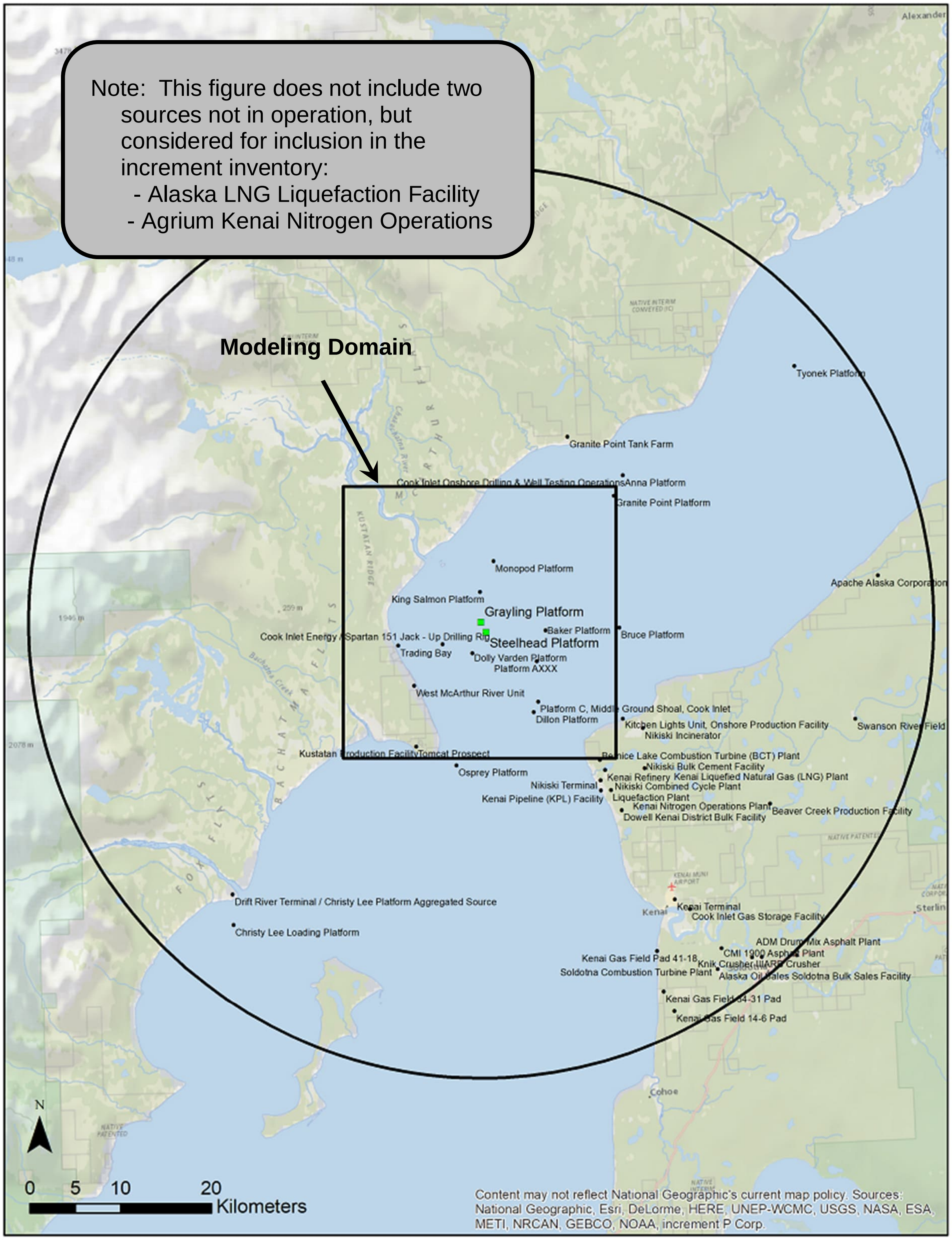
To reduce the burden of this analysis, the increment impact analysis conducted for the Project focuses on explicitly modeling emissions changes that are easy to document and occurred at sources with the largest potential to cause significant concentration gradients in the Project impact area. All other increment consuming and expanding impacts from all other sources have been accounted for by adding a representative background to the predicted impacts. Relying on a background concentration to account for all increment impacts not explicitly modeled will potentially overestimate increment impacts because it may include impacts from sources modeled explicitly, international sources, naturally occurring sources, and mobile and stationary sources with impacts at the Minor Source Baseline Date. The same background concentration used to account for non-modeled sources in the AAQS cumulative impact analysis was used for the PSD increment analysis.

To determine stationary sources and source emissions units to include in the increment modeling, Hilcorp selected sources among the Title V Major sources operating within a ring located approximately 50 km beyond the modeling domain. **Figure F2-1** shows the modeling domain, the 50-km ring and the regional sources falling within that ring. This figure shows that this approach is sufficient to capture all regional sources.

Because very little data are available for baseline emissions, Hilcorp only considered increment consuming emissions units in this analysis. Thus, all emissions units installed before the Minor Source Baseline Date have “zero” emissions and increment expanding units were not included in the analysis.

Similarly, very little data are available for emissions increases that have occurred over time at sources that began operation after the Minor Source Baseline Date. Therefore, Hilcorp assumed that baseline source emissions have not materially changed since the baseline date, resulting in no additional increment consumption for these sources. If this assumption is incorrect, that increment consumption should be small and accounted for in the background concentrations added to model-predicted impacts.

Figure F2-1: Existing Sources within ~50 km of the Grayling Platform Modeling Domain



Note: This figure does not include two sources not in operation, but considered for inclusion in the increment inventory:
- Alaska LNG Liquefaction Facility
- Agrium Kenai Nitrogen Operations

Content may not reflect National Geographic's current map policy. Sources: National Geographic, Esri, DeLorme, HERE, UNEP-WCMC, USGS, NASA, ESA, METI, NRCAN, GEBCO, NOAA, increment P Corp.

Using this strategy, Hilcorp then investigated the inventories of all sources within the ring shown in **Figure F2-1** and determined if the source is still operational. The following sources were not modeled because they do not appear to be in operation or have little to no actual emissions to model:

- Baker Platform – Only small emissions units with low emissions remain.
- Trans-Foreland Pipeline Company LLC, Kenai LNG Plant
- Dillon Platform – Only small emissions units with low emissions remain.
- Drift River Terminal and Christy Lee Loading Platform – Aggregate source has been recently decommissioned and is no longer operating.
- Osprey Platform – Platform is not operating at the time of this application.
- West McArthur River Unit – No Title V or Title I permits exist, so facility is assumed to not be operating.

With non-operational sources removed from the inventory, Hilcorp then determined which sources could be excluded based on the age of the inventory. Inventories were constructed for the remaining sources with the installation year included. Sources with large inventories of emissions units in operation at the Minor Source Baseline Date where most emissions come from the baseline emissions units were excluded from the analysis as follows:

- Beluga River Power Plant
- Swanson River Field

Once again, if this assumption is not correct, any increment consumption should be small and will be accounted for in the background concentrations added to model-predicted impacts prior to comparison to increment thresholds.

For the remaining sources, Hilcorp identified the increment-consuming emissions units in each inventory. Most of the remaining sources are owned and operated by Hilcorp, so actual emissions were readily available. For sources owned by other companies, Hilcorp used potential emissions based on the operating permit applications readily available on ADEC’s website, with small changes such as assuming emergency equipment rarely operates. Since an increment analysis is based on actual changes in emissions since the Minor Source Baseline Date, relying on permitted allowable emissions is expected to overestimate increment impacts.

Other than the Dolly Varden and Steelhead Platforms, the sources included in the increment analysis were simulated as single point sources to reduce the number of inputs required for the OCD model. The stack parameters and platform/ on-site emissions unit information was obtained from previous modeling analyses. **Table F2-7** shows a summary of the point sources and parameters used in the increment analysis.

Table F2-7: Inventory of Point Sources Included in the Increment Analysis

SOURCE	X-Coord [2] (m)	Y-Coord [2] (m)	Short Term SO_2 ER (g/s) [1]	Bldg Top (m)	Stack Height (m)	Temp (K)	Stack Dia (m)	Stack EXIT Velocity (m/s)	Stack Angle [3]	Deck Elev (m)	Deck Width (m)
Bernice Lake Power Plant	12,658	-15,992	0.1381	10	7.6	777	1.02	52.1	0	50	36.6
Granite Point Platform	14,971	13,561	5.4823	15.03	15.2	777	0.58	36.5	90	10.2	36.6
Anna Platform	15,807	15,633	0.9630	15.3	6.7	777	1.07	52.1	0	11.2	33.5
Monopod Platform	1,702	6,407	0.2457	14.05	6.7	777	1.07	52.1	0	10.35	32.9
Tesoro Refinery	13,870	-17,042	3.8438	10	7.6	777	1.02	52.1	0	50	36.6
Platform A	6,300	-4,777	0.3596	10	6.7	777	1.07	52.1	0	11.2	36.6
Granite Point Tank Farm	9,896	20,032	0.0495	10	7.6	777	1.02	52.1	0	50	36.6
Kenai Gas Field Pad 34-31	20,887	-42,924	0.2066	10	7.6	777	1.02	52.1	0	50	36.6

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Table F2-7 (Continued): Inventory of Point Sources Included in the Increment Analysis

SOURCE	X-Coord [2] (m)	Y-Coord [2] (m)	SO_2 ER (g/s) [1]	Bldg Top (m)	Stack Height (m)	Temp (K)	Stack Dia (m)	Stack Exit Velocity (m/s)	Stack Angle [3]	Deck Elev (m)	Deck Width (m)
Trading Bay Production Facility	-35,327	-27,334	0.1612	10	7.6	777	1.02	52.1	0	50	36.6
Nikiski Combined Cycle Plant	12,689	-18,466	0.5539	10	7.6	777	1.02	52.1	0	50	36.6
Soldotna Combustion Turbine Plant	34,639	-37,053	0.1746	10	7.6	777	1.02	52.1	0	50	36.6
AGDC AKLNG Liquefaction Facility [4]	14,360	-19,567	2.77	10	7.6	777	1.02	52.1	0	50	36.6
Agrium KNO [5]	13,118	-18,140	0.413	10	7.6	777	1.02	52.1	0	50	36.6

[1] The same emission rate was used for both the short-term and long-term modeling.

[2] X-Y Coordinates are relative to platform center.

[3] Stack Angle: vertical = 0 degrees, horizontal = 90 degrees, and downward = 180 degrees.

[4] AGDC based on 2.77 g/s SO_2 excluding maximum flare case documented by the State in a spreadsheet called “aq1539cpt01-emission-calculations-department.xlsx” retrieved from https://dec.alaska.gov/air/air-permit/liquefaction-plant-application/ on 3/2/2021.

[5] Agrium KNO based on a PTE of 3.28 lb/hr SO_2 documented by the state in a spreadsheet called “aq0083cpt07-emission-calculations-department-updated.xlsx” retrieved from https://dec.alaska.gov/air/air-permit/agrium-kenai-nitrogen-plant/ on 3/2/2021.

The Steelhead and Dolly Varden Platforms were included in the increment analysis off-site inventory as individual emissions units rather than single point sources. This is because the proximity of these sources to the Grayling Platform warranted a refined characterization.

Dolly Varden's inventory was modified to include only increment consuming emissions units. This excludes EU IDs 1, 2, and 5 through 10, which were installed prior to the baseline date. The emission rates are the same as those in the cumulative demonstration (see **Table F2-5)**. For the Steelhead Platform, the emission inventory used in the cumulative modeling is the same as that shown in **Table F2-5** because all emissions units on the Steelhead Platform were installed after the SO_2 baseline date.

The Grayling Platform has a mix of baseline and increment consuming units. While this is the case, this analysis does not take credit for actual emissions occurring at the Minor Source Baseline Date. Therefore, modeled increment consuming emission rates are the same as those used for the cumulative modeling which account for the total SO_2 emissions following the implementation of the Project.

Temporary emissions units, such as the Kuukpik V transportable drill rig and the service vessels were excluded from this analysis. Drilling and service vessels like these were in operation at the Minor Source Baseline Date combusting fuel with a higher sulfur content than fuels combusted today. Therefore, it is likely that impacts from these sources are increment expanding and excluding them from the analysis provides a more conservative assessment of platform increment impacts.

The results of the Class II area increment modeling for SO_2 emissions are shown in **Table F2-8**. This table shows that the Project will not result in a violation of the SO_2 Class II PSD Increments.

The Tuxedni National Wildlife Refuge (NWR), located 80 km from the Grayling Platform, is the nearest Class I area to the platform. This distance is beyond the functional limit of steady state dispersion models, including the OCD model. Therefore, impacts were predicted on an arc of receptors placed approximately 50 km from the platform between the platform and the Tuxedni NWR. Since concentrations will decrease with distance beyond 50 km, impacts at the Tuxedni NWR will be lower. The results of cumulative increment impacts predicted on an arc 50 km from the platform are shown in **Table F2-9** compared to the allowable Class I increments. As shown, the Project will not result in a violation of the SO_2 Class I PSD Increments on the 50-km arc and any Class I areas beyond this arc.

Table F2-8: SO_2 PSD Class II Cumulative Increment Impact Analysis with a Source-Wide Fuel Gas H_2S Concentration of 1,250 ppmv

Pollutant	Averaging Period	Predicted Concentration [1] (μg/m^3)						Background (μg/m^3)	Total (μg/m^3)	Class II Increment (μg/m^3)	% Increment
		2012-13	2013-14	2014-15	2017-18	2019	Max.				
SO_2	Annual	13.4	12.7	14.3	13.4	12.6	14.3	0	14.3	20	72
	24-hour	79.5	74.5	63.8	73.5	76.5	79.5	0	79.5	91	87
	3-hour	149	132	145	157	150	157	0	157	512	31

[1] All concentrations are maximum predicted impacts for the averaging period.

Table F2-9: SO_2 PSD Class I Cumulative Increment Impact Analysis with a Source-Wide Fuel Gas H_2S Concentration of 1,250 ppmv

Pollutant	Averaging Period	Predicted Concentration [1] (μg/m^3)						Background (μg/m^3)	Total (μg/m^3)	Class I Increment (μg/m^3)	% Increment
		2012-13	2013-14	2014-15	2017-18	2019	Max.				
SO_2	Annual	0.46	0.44	0.49	0.48	0.44	0.49	0	0.49	2	22
	24-hour	3.44	3.81	2.95	4.39	3.63	4.39	0	4.39	5	88
	3-hour	10.0	12.6	12.7	11.6	9.8	12.7	0	12.7	25	50

[1] All concentrations are maximum predicted impacts for the averaging period.

F3. Qualitative Source Impact Analysis

In addition to conducting the quantitative $PM_{2.5}$ impact analysis presented in Section F2.2, Hilcorp has also conducted a qualitative $PM_{2.5}$ source impact analysis to demonstrate that the Project will not cause or contribute to a violation of the AAQS and PSD Class I and II increment. Relying on a qualitative analysis should be sufficient because the Cook Inlet is one of those unique situations where photochemistry is either limited or not possible for portions of the year. In those situations, USEPA indicates it may be acceptable to rely upon a qualitative approach to assess secondary impacts.

For the qualitative analysis HIlcorp assumed that only impacts from secondary $PM_{2.5}$ need to be investigated because there are no increases in direct $PM_{2.5}$ emissions from the Project, precursor emissions are suitably low, and sufficient technical information exists to be able to build a qualitative impact analysis. The following elements related to addressing Project $PM_{2.5}$ impacts were reviewed to support the qualitative analysis:

- Secondary particulate formation in the Project region;
- Existing monitoring data for $PM_{2.5}$ and other pollutants related to secondarily formed $PM_{2.5}$; and
- Potential direct and secondary $PM_{2.5}$ impacts.

F3.1 Understanding Regional Secondary $PM_{2.5}$ Formation

The analysis provided in this section relies heavily on a comprehensive analysis of regional secondary $PM_{2.5}$ formation presented in the construction permit application materials for the Alaska LNG project. That project is located within 25 km of the Grayling Platform and the information provided in that application is applicable to this Project given their proximity.

F3.1.1 $PM_{2.5}$ Formation Processes

$PM_{2.5}$, or “fine” particulate matter, undergoes a series of complex processes that ultimately lead to their formation and establish their atmospheric lifetimes. Generally, fine particles are subject to the following general formation and removal pathways:

- **Nucleation**. This process describes the rate at which a transformation of phase occurs as the very first small nuclei appear. The nucleation of trace substances and water from the vapor phase to the liquid or solid phase is of primary concern in the atmosphere. Heterogeneous nucleation is the nucleation on a foreign surface or substance, and it readily allows the formation in air of water droplets when the relative humidity is only slightly above 100%.
- **Chemical reactions**. A significant number of chemical reactions occur between gas phase precursors that eventually lead to the formation of particulate matter in the atmosphere. Generally, hundreds to thousands of chemical reactions occur, depending on the chemical species involved. The ultimate compositions of these particulates in the atmosphere include sulfate, nitrate, ammonium, elemental carbon, organic compounds, water, and metals.
- **Condensation**. This process involves particle populations, and it refers to vapor that condenses on particles or when material evaporates from the aerosol to the gas phase. This process tends to change the size of the particles; usually the growth of the particles

is governed by the diffusion coefficient for each species, as well as the vapor pressure difference between chemical species and the equilibrium vapor pressure.

- **Coagulation**. This process involves particle growth as the result of one or more particles suspended in the atmosphere colliding because of Brownian motion or other hydrodynamic, electrical, gravitational, or other forces.
- **Cloud processing and removal**. Aerosols can activate under supersaturation conditions and lead to the formation of cloud droplets; in other words, they act as cloud condensation nuclei. Once processed in this manner they could be removed from the atmosphere following precipitation events or they could also undergo aqueous phase chemistry. Finally, precipitation can also remove a significant number of particles from the atmosphere as the cloud droplets interact with aerosols.

Fine particles are usually the result of the processes mentioned above and are typically formed in the atmosphere. As a result, $PM_{2.5}$ is generally composed of particles that had multiple sources, such as combustion (coal, oil, gasoline, diesel, wood, etc.) and gas to particle conversion of precursors, such as oxides of nitrogen (NO_X), SO_2, and volatile organic compounds (VOCs).

F3.1.2 $PM_{2.5}$ Lifetimes

The estimated $PM_{2.5}$ lifetime in the troposphere varies significantly depending on altitude, latitude, and season. $PM_{2.5}$ lifetimes could easily vary between a few days up to several weeks. Once formed, particles could be subjected to meteorological transport over significant regional scales that range from hundreds to thousands of miles.

An important consideration in the lifetime of particulate nitrate and sulfate, which are $PM_{2.5}$ components usually associated with anthropogenic sources, is the availability of ammonia. Ammonia is the dominant alkaline gas in the atmosphere and plays an important role in the formation of ammonium nitrate or sulfate. In mid-latitudes the major anthropogenic source is agriculture (fertilization and animal husbandry) with biomass burning, transport, and industry being minor contributors. Natural sources include soils, vegetation, oceans, and animal excreta. Anthropogenic sources are expected to contribute minimally to ammonia levels in the Cook Inlet region due to a lack of agriculture and industry. Furthermore, ammonia is short lived in the atmosphere so it is unlikely that long range transport would bring significant amounts of ammonia from lower latitudes to the region.

Natural sources, such as biomass burning, could inject important amounts of ammonia, so wildfires could play an important episodic role in regional ammonia concentrations. Additionally, in some settings, the ocean can be an important dominant source of ammonia via remineralization of organic matter by bacteria and phytoplankton excretion (Carpenter et al. 2012). Though this is the case, at high latitudes the ocean and melt ponds are generally net sinks. Likely more relevant to the Cook Inlet, Wentworth et. al. (2016) concluded that seabird colonies and the associated guano are the dominant and persistent local source of ammonia in the summertime at high latitudes. The same has been shown for large seal colonies (Theobald et al. 2006). Regardless of the source, Wentworth et al. (2016) documents that ammonia concentrations in Arctic ecosystems could range between 0.03 and 0.6 micrograms per cubic meter ($\mu g/m^3$)
(0.040 – 0.870 ppbv) during the summer, which is still 1 to 2 orders of magnitude lower than typical ammonia concentrations over the continental United States (0.1 to 10 ppbv). This lack of ammonia at high latitudes limits nitrate and sulfate formation in these areas.

F3.1.3 Source and Distance Relationship on $PM_{2.5}$ Concentrations

The spatial distribution of $PM_{2.5}$ over large distances from a single source is, in part, a function of the chemical species involved. For instance, particles that contain significant amounts of sulfate will be longer lived in the atmosphere than those with only nitrate, because nitrate is semi-volatile and, thus, able to convert back into the gas phase. Other more inert species like fine dust will be subjected to dispersion and gravitational settling without their lifetimes being significantly affected by chemical processes. The presence and absence of clouds and the amount of sunlight also determine the rate at which pollutants are converted to other pollutants, for example, sulfur dioxide gas to sulfate particles.

Wind is an important process for mixing the earth's atmosphere and dispersing pollutants. Pollutants produced under stagnant conditions can become trapped and create a layered haze, whereas pollutants produced under windy conditions are well mixed and dispersed and appear as a uniform haze. At times, the marine boundary layer inversion may have the potential to trap aerosols at low elevations in the Cook Inlet, although there are no significant local sources of particulate matter. Subsidence inversion and stagnation and concurrent aerosol buildup could occur during periods of persistent regional high pressure in the summer, and when the southward spread of polar air drops temperatures and is conducive to such conditions. This is less likely to occur during winter periods when the Aleutian Low is strongest (COHA 2021).

Baker et al. (2016) performed photochemical modeling simulations of 24 hypothetical single sources in the continental United States to estimate their impacts to ozone and $PM_{2.5}$ concentrations. The modeling showed that downwind impacts varied directionally from each source due to differences in meteorology and chemical environment near the source. An aggregate analysis of daily maximum 24-hour average $PM_{2.5}$ impacts as a function of the distance from the source shows that maximum impacts from secondary formation are not located in close proximity to the modeled emissions sources, but rather at a distance further downwind than where the peak direct $PM_{2.5}$ impact occurs and somewhere less than 50 km downwind. Following the peak, the $PM_{2.5}$ concentrations will decrease as the distance increases. Baker et al. (2016) shows that typical impacts for sulfate $PM_{2.5}$ tend to peak at approximately 10 km from the source and then rapidly decrease with distance with almost no impacts after 20 or 30 km from the source. Nitrate impacts are the largest at a distance of about 5 to 10 km from the source and decrease with distance, but impacts could be as large as 0.2 $\mu g/m^3$ at a distance of 100 km from the source depending on source strength and background ammonia.

F3.2 Reviewing Existing Data Important to Understanding Regional $PM_{2.5}$ Concentrations

F3.2.1 Existing $PM_{2.5}$ Concentrations

There is no typical or uniform ambient background concentration of $PM_{2.5}$ given that it could be composed of multiple chemical species. Urban environments in the continental United States typically have some of the highest $PM_{2.5}$ concentrations that could exceed more than 12 $\mu g/m^3$ on an annual average. Rural and remote environments will usually show both different compositions and lower annual concentrations that could range from 5 to 10 $\mu g/m^3$. However, some areas might be influenced by desert aerosols, which originate in deserts from wind disturbance but could extend considerably over adjacent regions. It is well documented that dust storms from the Sahara could transfer material across the Atlantic Ocean and affect the east coast of the United States. Also, coastal areas might be influenced by marine aerosols.

The Graying Platform is located close to Anchorage, Alaska. Kim and Hopke (2008) performed a characterization of ambient fine particles using source apportionment techniques in the Northwestern United States and Anchorage. They found that gasoline vehicles, secondary sulfates, and wood smoke were the largest sources of $PM_{2.5}$ in the region. Secondary sulfates showed an April peak in Anchorage which they linked to increased photochemical reactions and long-range transport. Ward et al. (2012) performed a source apportionment study in the subarctic airshed of Fairbanks, Alaska. They found that $PM_{2.5}$ concentrations average between 22 and 26 µg/m^3 with frequent exceedances of the 24-hour AAQS. Their analysis using Chemical Mass Balance indicated that wood smoke from residential combustion was the major source of $PM_{2.5}$, contributing between 60 percent and 80 percent of the measured PM. Wang and Hopke (2014) also performed a source apportionment study in Fairbanks, Alaska. This analysis shows similar results with wood smoke being the highest contributor (~40 percent) to $PM_{2.5}$ concentrations, followed by secondary sulfates and gasoline. Wang and Hopke (2014) conclude that winter heating is the most important factor affecting the air quality in Fairbanks. Based on measurements made in Nikiski, 24-hour $PM_{2.5}$ concentrations ranged from 8 to 24 µg/m^3 with measurements as high as 71 µg/m^3, when impacted by wildland fires. Annual $PM_{2.5}$ concentrations were less than 4 µg/m^3 (ADEC 2021).

F3.2.2 Source and Regional Emissions

The total potential change in $PM_{2.5}$ precursor emissions from the Grayling Platform would be 0 tpy of NO_X and less than 300 tpy of SO_2. This represents less than 2 percent of the total NO_X and SO_2 emissions in the Kenai Peninsula Borough, which are summarized in **Table F3-1**. This percentage shows the small potential for the Project to contribute to regional $PM_{2.5}$ formation and concentrations. Since the region is currently attaining the 24-hour and annual $PM_{2.5}$ AAQS, the minor increase in $PM_{2.5}$ precursors from the Project compared to regional emissions indicates the Project will not reasonably pose a threat to regional $PM_{2.5}$ AAQS attainment.

F3.3 Potential $PM_{2.5}$ Impacts

$PM_{2.5}$ concentrations are difficult to evaluate as particulates are formed by multiple chemical species. However, Baker et al. (2016) investigated the modeled peak 24-hour $PM_{2.5}$ sulfate and nitrate concentrations response to SO_2 and NO_x emissions. Baker et al. (2016) found that the 24-hour $PM_{2.5}$ nitrate concentrations would increase between 0.1 and 0.8 µg/m^3 when the emissions of a single source range between 0 and 500 tpy. The Project will result in no increase in the potential to emit NO_x and, therefore, will not lead to additional nitrate formation. Baker et al. (2016) also found that SO_2 emissions in the range of 500 to 1,000 tpy, would result in sulfate ion 24-hour $PM_{2.5}$ concentrations that range between 0 and 2 µg/m^3. The Project increase in SO_2 emissions is less than 300 tpy and, therefore, should not result in a noticeable increase in $PM_{2.5}$ resulting from secondary formation. These estimates represent an upper limit given that regional sulfate and nitrate formation are significantly limited by the unavailability of ammonia in the atmosphere.

For $PM_{2.5}$, the presented analysis indicates that Project emissions would lead to no nitrate particulate with a potential sulfate $PM_{2.5}$ increase of less than 2 µg/m^3 for the 24-hour averaging period. These estimated $PM_{2.5}$ impacts are not expected to occur near the source, but downwind as the result of secondary formation. This increase would occur in a region where 24-hour $PM_{2.5}$ concentrations range around 10 µg/m^3 and would not lead to nonattainment issues in the region.

Table F3-1: Regional Anthropogenic Emissions Near the Grayling Platform

NEI Tier 1 Category	Total Reported Emissions (NEI 2017) (tpy)		
	NO_X	Primary $PM_{2.5}$	SO_2
Fuel Comb. Elec. Util.	1,107	14	16
Fuel Comb. Industrial	4,424	245	143
Fuel Comb. Other	767	1,881	80
Highway Vehicles	1,742	71	4
Miscellaneous	94	1,604	54
Natural Resources	1,023	-	-
Off-Highway	1,905	73	46
Other Industrial Processes	6	19	0
Petroleum & Related Industries	384	22	47
Storage & Transport	0	0	0
Waste Disposal & Recycling	0	3	0
Grand Total	11,453	3,932	389

F4. Additional Impacts Analysis

This section describes the PSD analyses that assess potential impacts on soils, vegetation, and visibility in the Project area caused by emissions from the modification in combination with emissions from growth in the area due to the Project. The additional impact analysis required in 40 C.F.R. 52.21(o) consists of the following components:

- **Growth Analysis**: an analysis of the air quality impact predicted for the area because of general commercial, residential, industrial and other growth associated with the source or modification (40 C.F.R. 52.21(o)(2)).
- **Soil and Vegetation Impact Analysis**: a discussion of predicted ambient air quality impacts relative to soils and vegetation in the Project impact area having significant commercial or recreational value (40 C.F.R. 52.21(o)(1)).
- **Visibility Impairment Analysis**: an estimate of the impacts due to source emissions on the visual quality in the area. This analysis is typically an assessment of plume blight and not regional haze (40 C.F.R. 52.21(o)(1)).

F4.1 Growth Analysis

The growth analysis consists of a projection of the associated industrial, commercial, and residential growth that is likely to occur in the area due to the Project and an estimate of the emissions generated by that associated growth. Increasing the source-wide fuel gas H_2S limit will not result in a production increase or any population growth in the Project area; therefore, the Project is not expected to lead to any short-term or long-term associated industrial, commercial, or residential growth in the Project area. As such, additional impacts on air quality, soils, vegetation, and visibility due to growth associated with the Project are described by the Project and cumulative modeling and analyses presented in Section F2 and Section F3.

F4.2 Soil and Vegetation Impact Analysis

This analysis involves an assessment of the ambient air quality impacts on the soil and vegetation types found in the Project area. When making this assessment, it is important to note that most of the Project impact area occurs over water where there is neither soil nor vegetation. Regardless, this analysis has been carried out ignoring this consideration at this time.

The South-Central Alaska region is diverse, including an area from the peaks of the Alaska Range to the coastal marshes of the Kenai Peninsula, resulting in a wide range of soil and vegetation types. The Project is located over water in the upper Cook Inlet, which is in a transition zone between the maritime and continental zones with little to no permafrost. The area is characterized as a glaciated lowland containing areas of ground moraine and stagnant ice topography, drumlin fields, eskers, and outwash plains with rugged mountains located to the west and east. Soils consist of marine, glacial, alluvial, and volcanic ash deposits that have been altered by glacial action and erosion. The surface soils and features in the area have been created by several major glacial events, which included the deposition of marine sandy clay. Vegetation in the region includes over 19 forest types, 7 herbaceous types, and 6 shrub types growing from barren alpine regions to coastal salt marshes (Gallant et al. 1995).

F4.2.1 Vegetation Impact

To assess if the Project has the potential to cause deleterious effects to vegetation in the Project area, a comparison of the Project impacts can be made to threshold screening values developed by the USEPA from available laboratory and field studies (USEPA 1980). These thresholds “represent the minimum concentrations at which adverse growth effects or tissue injury in exposed vegetation were reported” to occur for sensitive plant species. Because it is more convenient and more protective, for most vegetation, ADEC recommends that the secondary National Ambient Air Quality Standards (NAAQS) are protective of vegetation species in Alaska (ADEC 2018). Secondary NAAQS set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. The AAQS are equivalent to, or more stringent than, these threshold screening values. Therefore, a project that demonstrates compliance with the AAQS demonstrates compliance with secondary NAAQS and indicates the project will not cause deleterious effects to vegetation.

The exception in Alaska are lichen species, which are particularly sensitive to SO_2 since they lack roots and derive all growth requirements from the atmosphere (Treshow and Anderson 1989). A United States Forest Service study conducted in the Tongass National Forest in southeast Alaska suggests 13 µg/m^3 as a worst-case sensitivity threshold for lichen species found there. While it is not known whether species of lichens found in the Project impact area have the same sensitivity as those in the Tongass National Forest, the sensitivity threshold still provides a reasonable surrogate measure. Therefore, based on ADEC recommendations, the secondary NAAQS has been supplemented with an annual SO_2 limit of 13 µg/m^3.

Table F4-1 summarizes the vegetation impact analysis, which presents the totals of the cumulative modeled impact (Project plus off-site sources) and background concentration. The results in **Table F4-1** indicate that the total impact for all averaging periods is below appropriate vegetation exposure levels for Project area plant species.

Table F4-1: Vegetation Impact Analysis

Pollutant	Averaging Period	Cumulative Impact (µg/m^3)			Vegetation Exposure Threshold (µg/m^3)
		Maximum Modeled Impact	Ambient Background Concentration	Total Impact	
SO_2	Annual	3.2 [1]	0.0	3.2	13 [2]
	3-hour	158	0.0	158	1,300 [3]

[1] Maximum annual impact at receptors located 8 km from the platform. Receptors within this distance are over water and do not need to be included in this analysis due to lack of vegetation.

[2] Threshold determined by ADEC to be applicable to lichens which may exist in the Project area (ADEC 2018).

[3] Secondary NAAQS – Recommended by ADEC as the appropriate limit to protect against damage to crops and vegetation.

F4.2.2 Soils Impact

According to USEPA (1980), there is little information available on the effects of air pollutants on soils. Deposition of trace elements may have some effect on soils, but “secondary effects of the pollutant appear to impact the soil system more adversely than the addition of the pollutant itself to the soil. For instance, damaging or killing vegetative cover could lead to increased solar radiation, increased soil temperatures, and moisture stresses,” in addition to increased runoff and erosion. Thus, impacts on nearby soils were evaluated by determining the potential effect of Project emissions on vegetation. As discussed in the previous section, vegetation impacts were found to be below applicable vegetation exposure thresholds. Therefore, impacts to soils in the Project area are expected to be insignificant.

F4.3 Visibility

The visibility impairment assessment involves a plume blight analysis to determine the impacts of a proposed modification emissions on the visual quality of an area. Plume impairment is generally defined as the pollutant loading of a portion of the atmosphere such that it becomes visible, by contrast or color difference, against a viewed background such as a landscape feature or the sky. The evaluation criteria for plume impairment are the color difference index (ΔE) and plume contrast (C_p). This air quality related value is generally applied at near-field (approximately less than 50 km) locations and modeled using the Level 1 or Level 2 VISCREEN screening model or the PLUVUE II model if more information is required.

There are only two common plume constituents that scatter or absorb light and contribute to plume visibility - particulates, depending on their nature, and NO_2 (USEPA 1992). For the Project, SO_2 is the only directly emitted pollutant subject to PSD review. SO_2 emissions are not available as input to VISCREEN. Moreover, the issue of secondary sulfate formation (SO_4) is not treated in VISCREEN because of the limited range of applicability of a steady state Gaussian dispersion model and because of the uncertainty of estimating the conversion of SO_2 to SO_4 in a coherent plume. Furthermore, it is not anticipated that the fuel gas combustion devices on the platform produce a near-field plume with a significant component of primary sulfate in a size range that has maximum light scattering efficiency. Therefore, the effects from primary sulfate emissions can be ignored. Since SO_2 does not contribute to plume visibility in the model and primary sulfate emissions are small, there will be negligible visibility impairment associated with the Project.

F5. Sources Impacting Class I Areas – Additional Requirements

As part of the PSD rules promulgated under 40 C.F.R. 52.21 and adopted by reference in 18 AAC 50.040 with the changes indicated in 18 AAC 50.306, an analysis of additional impacts on Class I areas must be submitted to reviewing authorities as part of a PSD permit application.

Alaska has four Class I areas to consider: Denali National Park (NP), Simeonof NWR, Bearing Sea Wilderness Area, and the Tuxedni NWR. None of these are in the near field (i.e., within 50 km) of the Project. The New Source Review Workshop Manual (USEPA 1990) and guidance provided by the National Park Service (USDOI 2010) suggest that generally a 100-km range is an acceptable modeling domain unless the source being considered is large and could reasonably affect the outcome of a Class I analysis. Given the relatively small Project emissions and distance (>230 km), it is highly unlikely that Grayling Platform emissions could materially affect ambient air quality and air quality-related values (AQRVs) at Denali National Park, Simeonof NWR, or the Bearing Sea Wilderness Area. However, the Tuxedni NWR is 80 km from the Project and merits additional consideration.

To provide evidence that a comprehensive AQRV impact analysis does not need to be conducted for the Tuxedni NWR, the USDOI 2010 initial screening procedure, commonly referred to as the “Q/d” test, for projects greater than 50 km from a Class I area was conducted. The analysis shows that the ratio of the sum of the Project’s annual SO_2, NO_X, particulate matter less than 10 microns in diameter (PM_{10}), and sulfuric acid (H_2SO_4) emissions in tons per year (based on a worst-case 24-hour emissions scenario) to the distance to the Class I area in kilometers is less than 10. **Table F5-1** presents the analysis details. Since the Q/d value for the Project is less than 10, it is assumed that the Project will have negligible impacts with respect to Class I AQRVs.

Table F5-1: Project Q/d Analysis at the Tuxedni NWR

Scenario	Change in Maximum 24-Hour Potential Emissions (tpy)				Distance	Q/d
	SO_2	NOx	PM_{10}	H_2SO_4		
Non-Emergency Operations	226 [1]	0	0	0	>80 km	2.8
Emergency Flaring	1.12	0	0	0		0.01
Non-Emergency Operations + Emergency Flaring	227	0	0	0		2.8

[1] Represents the difference between actual SO_2 emissions and future potential SO_2 emissions at 1,250 ppmv H_2S in the combusted gas. The change in actual emissions would be smaller.

F6. References

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Grayling Platform

Fuel Gas H_2S Increase Project Construction Permit Application

Attachment G – Copy of Permit No. AQ0069MSS04, Revision 1

Hilcorp Alaska, LLC

3800 Centerpoint Drive, Suite 1400, Anchorage, AK 99503

Prepared by:

SLR International Corporation

2700 Gambell Street, Suite 200, Anchorage, Alaska, 99503

SLR Project No.: 105.00874.20026

October 2023

DEPARTMENT OF ENVIRONMENTAL CONSERVATION
AIR QUALITY CONTROL MINOR PERMIT

Minor Permit: **AQ0069MSS04, Revision 1** **Final Date – November 6, 2020**

Rescinds Permit: AQ0069MSS04

The Alaska Department of Environmental Conservation (Department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Minor Permit AQ0069MSS04, Revision 1 to the Permittee listed below.

Permittee:	**Hilcorp Alaska, LLC** 3800 Centerpoint Drive, Ste. 1400 Anchorage, AK 99503
Stationary Source:	**Grayling Platform**
Location:	60° 50’23” N; 151° 36’47” W
Project:	H_2S Increase
Permit Contact:	Julieanna Potter, (907) 777-8444

The Permittee submitted an application for Minor Permit AQ0069MSS04, Revision 1 under 18 AAC 50.508(6) in order to revise the terms and conditions of a Title I permit. The project is also classified under 18 AAC 50.502(c)(3) due to an increase in Sulfur Dioxide (SO_2) emissions greater than 10 tpy.

This permit satisfies the obligation of the Permittee to obtain a minor permit under 18 AAC 50. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this permit.

for

James R. Plosay,
Manager, Air Permits Program

Table of Contents

Section 1 Emissions Unit Inventory 1
Section 2 Fee Requirements 2
Section 3 ORLs to Avoid Permit Classifications 4
Section 4 Title I Conditions Carried Forward from Previous Permits 5
Section 5 Recordkeeeping, Reporting, and Certification Requirements 7
Section 6 Standard Permit Conditions 10
Section 7 Permit Documentation 11

Abbreviations and Acronyms

AAC	Alaska Administrative Code
ADEC	Alaska Department of Environmental Conservation
AOS	Air Online Services
AS	Alaska Statutes
ASTM	American Society for Testing and Materials
BACT	best available control technology
bhp	brake horsepower
CDX	Central Data Exchange
CEDRI	Compliance and Emissions Data Reporting Interface
C.F.R.	Code of Federal Regulations
CAA	Clean Air Act
CO	carbon monoxide
Department	Alaska Department of Environmental Conservation
dscf	dry standard cubic foot
EPA	US Environmental Protection Agency
EU	emissions unit
gr/dscf	grain per dry standard cubic foot (1 pound = 7000 grains)
gph	gallons per hour
HAPs	hazardous air pollutants [as defined in AS 46.14.990]
hp	horsepower
ID	emissions unit identification number
kPa	kiloPascals
LAER	lowest achievable emission rate
MACT	maximum achievable control technology [as defined in 40 C.F.R. 63]
MMBtu/hr	million British thermal units per hour
MMSCF	million standard cubic feet
MR&R	monitoring, recordkeeping, and reporting
NESHAPs	National Emission Standards for Hazardous Air Pollutants [as contained in 40 C.F.R. 61 and 63]
NOx	nitrogen oxides
NRE	nonroad engine
NSPS	New Source Performance Standards [as contained in 40 C.F.R. 60]
O & M	operation and maintenance
O_2	oxygen
PAL	plantwide applicability limitation
PM-10	particulate matter less than or equal to a nominal 10 microns in diameter
PM-2.5	particulate matter less than or equal to a nominal 2.5 microns in diameter
ppm	parts per million
ppmv, ppmvd	parts per million by volume on a dry basis
psia	pounds per square inch (absolute)
PSD	prevention of significant deterioration
PTE	potential to emit
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SPC	Standard Permit Condition or Standard Operating Permit Condition
SO_2	sulfur dioxide
The Act	Clean Air Act
TPH	tons per hour
tpy	tons per year
VOC	volatile organic compound [as defined in 40 C.F.R. 51.100(s)]
VOL	volatile organic liquid [as defined in 40 C.F.R. 60.111b, Subpart Kb]
vol%	volume percent
wt%	weight percent
wt%S_{fuel}	weight percent of sulfur in fuel

Section 1 Emissions Unit Inventory

Emissions Unit (EU) Authorization. The Permittee is authorized to operate the EUs listed in Table 1 in accordance with the minor permit application and the terms and conditions of this permit. The information in Table 1 is for identification purposes only, unless otherwise noted in the permit. The specific EU descriptions do not restrict the Permittee from replacing an EU identified in Table 1.

Table 1 – EU Inventory [a]

EU #	Tag No.	Name	Make/Model	Fuel	Rating/Max Capacity
1	G-PM-1020	#1 Bingham WF Pump Drive	Solar Centaur T4500	FG[b]	4,500 hp
3	G-PM-1030	#2 Bingham WF Pump Drive	Solar Centaur T4500	FG	4,500 hp
4	G-PM-0520	West Compressor Drive	Solar Centaur T4500	FG	4,500 hp
14	G-PM-0710	Oil Shipping Pump Drive	Solar Saturn T1200	FG	1,100 hp
15	G-PM-1120	#1 AC Gen Drive	Solar Saturn T1200	FG	800 kW
16	G-PM-1130	#2 AC Gen Drive	Solar Saturn T1200	FG	800 kW
17	G-PM-1140	#3 AC Gen Drive	Solar Saturn T1200	FG	750 kW
18	G-PM-1150	#5 AC Gen Drive	Solar Saturn T1200	FG	800 kW
19	G-B-1740	#1 Hp Glycol Water Heater	Continental Boiler	FG	7.3 Mscf/hr
20	G-B-1750	#2 Hp Glycol Water Heater	Continental Boiler	FG	7.3 Mscf/hr
24	G-CR-2040	West Crane	Cat 3406 Engine	Diesel	340 hp
25	G-CR-2050	East Crane – Skagit	Cat 3208 Engine	Diesel	250 hp
26	G-PM-1160	Emergency AC Gen Drive	Cat 3406-DI Engine	Diesel	300 kW
27	G-PM-1530	Fire Water Pump Drive	Cat D-330C Engine	Diesel	85 hp
28	G-SP-SO	Flare (South)	Flare (max rating 0.375 Mscf/hr)	FG	3 MMscf/day
29	G-SP-SW	Flare (SW)	Flare (max rating 0.375 Mscf/hr)	FG	
31	G-PM-1300	SoLoNOx Turbine	Solar Taurus 60 T-7300S	FG	5.2 MW

Notes:

[a] EUs listed in Table 1 have already been installed at the stationary source.

[b] FG means fuel gas.

1. The Permittee shall comply with all applicable provisions of AS 46.14 and 18 AAC 50 when installing a replacement EU, including any applicable minor or construction permit requirements.

Section 2 Fee Requirements

2. **Administration Fees.** The Permittee shall pay to the Department all assessed permit administration fees. Administration fee rates are set out in 18 AAC 50.400 – 499.

3. **Assessable Emissions**. The Permittee shall pay to the Department annual emission fees based on the stationary source's assessable emissions as determined by the Department under 18 AAC 50.410. The assessable emission fee rate is set out in 18 AAC 50.410. The Department will assess fees per ton of each air pollutant that the stationary source emits or has the potential to emit in quantities 10 tons per year or greater. The quantity for which fees will be assessed is the lesser of:

   3.1 the stationary source's assessable potential to emit of 1,159 tpy; or

   3.2 the stationary source's projected annual rate of emissions that will occur from July 1 to the following June 30, based upon credible evidence of actual annual emissions emitted during the most recent calendar year or another 12 month period approved in writing by the Department, when demonstrated by the most representative of one or more of the following methods:

      a. an enforceable test method described in 18 AAC 50.220;

      b. material balance calculations;

      c. emission factors from EPA's publication AP-42, Vol. I, adopted by reference in 18 AAC 50.035;

      d. other methods and calculations approved by the Department, including appropriate vendor-provided emissions factors when sufficient documentation is provided.

4. **Assessable Emission Estimates.** Emission fees will be assessed as follows:

   4.1 no later than March 31 of each year, the Permittee may submit an estimate of the stationary source's assessable emissions via the Department's AOS System at http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option and filling out the Emission Fee Estimate form. Alternatively, the report may be submitted by:

      a. Email under a cover letter using dec.aq.airreports@alaska.gov; or

      b. hard copy to the following address: ADEC, Air Permits Program, ATTN: Assessable Emissions Estimate, PO Box 111800, Juneau, AK 99811-1800 if sent through the U.S.P.S., or 410 Willoughby Ave., Suite 303, Juneau, AK 99801-1795 if sent through another carrier.

   4.2 The Permittee shall include with the assessable emissions report all of the assumptions and calculations used to estimate the assessable emissions in sufficient detail so the Department can verify the estimates.

4.3 If no estimate is submitted on or before March 31 of each year, emission fees for the next fiscal year will be based on the potential to emit set out in Condition 3.1.

Section 3 ORLs to Avoid Permit Classifications

18 AAC 50.502(c)(3) Avoidance Limits for NOx:

5. The Permittee shall limit the emissions of NOx from EU ID 31 to no more than 22.9 tpy.

   5.1 Limit the hours of operation of EU ID 31 to no more than 380 hours per rolling 12-month period when operating out of SoLoNOx mode.

      a. Install and maintain a non-resettable hour metered on EU ID 31.

      b. Record the hour meter reading for EU ID 31 at the beginning and end of periods when the unit is operating and SoLoNOx mode is not active.

      c. No later than the 15th day of each calendar month, record the hours of operation for EU ID 31 when SoLoNOx mode was not active during the previous month, then calculate and record the rolling 12-month total hours for EU ID 31 when SoLoNOx mode was not active.

      d. Report in the operating report submitted under the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50 all monitoring and recording performed under Conditions 5.1b and 5.1c; and

      e. Notify the Department under permit deviations as described in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50 when the Permittee operates in a manner inconsistent with Condition 5.1.

18 AAC 50.306 Avoidance Limits for CO:

6. The Permittee shall limit the CO emissions for EU ID 31 to no more than 99.4 tpy.

   6.1 Comply with the operational restriction of Condition 5.1.

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Section 4 Title I Conditions Carried Forward from Previous Permits[1]

Operating Hour Limits – EU IDs 24 – 27

7. Operate the Emergency AC Generator Drive, EU ID 26, for no more than 2,600 hours per year. Operate EU IDs 24, 25, and 27 for no more than 3,000 hours per year per unit.

    7.1 Monitor and record the hours of operation of EU IDs 24 – 27 for each month.

    7.2 Include copies of the records required by Condition 7.1 with the operating report required by the applicable operation permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50.

8. The Permittee shall limit the actual emissions from EU ID 3 as indicated in Table 2 below.

    8.1 Monitor, record, and report NOx emissions from EU ID 3 as described in the NSPS Subpart GG NOx requirements in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50, except that the most stringent NOx emisison limit set out in Table 2 applies where the Subpart GG periodic testing thresholds reference the Subpart GG NOx limit for EU ID 3. For each test, conduct concurrent Methods 1-4 or calculate emission rates using concurrent measured dilutent measurements and fuel consumption rates through Method 19.

    8.2 Notify the Department under excess emissions and permit deviations described in the applicable operating permit issued for the statioanry source under AS 46.14.130(b) and 18 AAC 50 if the emissions of nitrogen oxides, based on the most recent emission unit test, exceed any of the limits in Table 2.

Table 2 – Turbine BACT Emissions Limits

Contaminant	EU	BACT Emission Limits for Individual Turbines
NOx	3	130 ppmv and 22.4 lb/hr

Conditions to Protect Ambient Air Quality

9. **Fuel Gas Sulfur Content Limit.** The Permittee shall not burn fuel gas with a hydrogen sulfide (H_2S) content greater than 400 parts per million volume (ppmv), monthly average, stationary source-wide.

    9.1 The Permitee shall monitor and record the H_2S concentration in the fuel gas no less than monthly using the length-of-stain detector tube protocol covered by ASTM Method D 4810-88 and D 4913-89 or Gas Producer’s Association Method 2377-86.

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[1] These conditions were originally established in Permit-to-Operate 9423-AA0006 and reestablished in AQ0069MSS01. Condition 9 was revised in AQ0069MSS02 and AQ0069MSS04.

9.2 The Permittee shall monitor the fuel gas H_2S concentration at the following frequencies:

a. If the measured concentration is greater than 85% of the maximum allowable H_2S concentration (340 ppmv), monitor the fuel gas H_2S concentration weekly.

b. If the average of four consecutive weekly fuel gas H_2S concentrations is less than 340 ppmv, the Permitee may return to the monitoring specified in Condition 9.1.

9.3 The Permittee shall report the fuel gas H_2S concentration in the operating report described in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50.

10. **Fuel Oil Sulfur Content Limit.**

10.1 The Permittee shall burn only diesel or distillate fuel with a sulfur content of no greater than 0.5 percent by weight in liquid fired emisisons units. The Permittee shall monitor, record, and report as described in the applicable operating permit issued for the stationary source under AS 46.14.130(b) and 18 AAC 50.

Section 5 SO_2 Emissions Monitoring, Recordkeeping, & Reporting

11. **Monitoring.** The Permittee shall monitor SO_2 emissions from EU IDs 1, 3, 4, 14 through 20, 28, 29, and 31; calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 10 years following the beginning of operation under Minor Permit AQ0069MSS04.

11.1 Monitor and reord the amount of fuel gas burned in million standard cubic feet (MMscf) during each calendar month of the calendar year by either:

a. Using a fuel gas meter calibrated to manufacturer's specifications and accurate to within ± 5 percent; or

b. Using an hour meter and assuming manufacturer's full load fuel consumption rate.

11.2 Calculate the total SO_2 emissions for each calendar month of the calendar year using the amount of fuel gas recorded under Condition 11.1, the monthly H_2S content of the fuel gas measured as described in Condition 9.1, and the following equation:

$$SO_2(tons) = \frac{Fuel\ Gas\ (MMscf) *\ H_2S\ (ppmv) * 64\ \frac{lbs\ SO_2}{mol\ H_2S}}{379.4\ \frac{scf}{mol} * 2{,}000\ \frac{lbs}{ton}}$$

11.3 By the reporting date specified for the operating report which encompasses the reporting for the month of December, required by the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50 of each calendar year, calculate the total SO_2 emissions for EU IDs 1, 3, 4, 14 through 20, 28, 29, and 31 for the preceding calendar year.

11.4 By the reporting date for the operating report which encompasses the reporting for the month of December, requird by the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50 of each calendar yer, determine the net change in SO_2 emissions for the preceding calendar year as follows:

$$Net\ Change\ in\ SO_2\ Emissions = (SO_2\ Emissions\ Calculated\ in\ Condition\ 11.3) - 26.7\ tpy$$

12. **Recordkeeping.** The Permittee shall maintain the following records for EU IDs 1, 3, 4, 14 through 20, 28, 29, and 31 and make them available to the Department upon request:

12.1 The fuel gas consumed (MMscf) for each calendar month of the calendar year;

12.2 The weighted averatge fuel gas H_2S concentration (ppmv) data for each calendar month of the calendar year;

12.3 The total SO_2 emissions for each calendar month calculated under Condition 11.2 and supporting calculations used to obtain the emission estimates;

12.4 The total SO_2 emissions for each calendar year calculated under Condition 11.3 and the supporting calculations used to obtain the emission estimates; and

12.5 The net change in SO_2 emissions for each calendar year calculated under Condition 11.4.

13. **Reporting.** For EU IDs 1, 3, 4, 14 through 20, 28, 29, and 31, the Permittee shall report as follows:

13.1 Report in the operating report required by the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50 the following information:

a. SO_2 emissions for each calendar month of the calendar year calculated under Condition 11.2; and

b. In the final operating report for the calendar year, report the net change in emissions calculated under Condition 11.4 for the calendar year ending with the last month of the reporting period.

13.2 Within 60 days after the end of each calendar year, report the following information to the Department if the net change in SO_2 emissions calculated under Condition 11.4 for the preceding year reaches or exceeds 40 tpy[2]:

a. The name, address, and telephone number of the major stationary source;

b. The annual emissions calculated under Condition 11.3 and the net change in emissions calculated under Condition 11.4; and

c. Any other information that the Permittee wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

13.3 Report as a permit deviation as describeed in the operating permit issued to the stationary source under AS 46.14.130(b) and 18 AAC 50 if monitoring, recordkeeping, or reporting under Conditions 11, 12, or 13 is not completed as required.

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[2] Hilcorp Alaska, LLC is required to submit a PSD application if the net change in emissions calculated under Condition 11.4 for the preceding year reaches or exceeds 40 tpy.

Section 6 Recordkeeping, Reporting, and Certification Requirements

14. **Certification.** The Permittee shall certify any permit application, report, affirmation, or compliance certification submitted to the Department and required under the permit by including the signature of a responsible official for the permitted stationary source following the statement: "*Based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.*" Excess emissions reports must be certified either upon submittal or with an operating report required for the same reporting period. All other reports and other documents must be certified upon submittal.

    14.1 The Department may accept an electronic signature on an electronic application or other electronic record required by the Department if

    a. A certifying authority registered under AS 09.25.510 verifies that the electronic signature is authentic; and

    b. The person providing the electronic signature has made an agreement with the certifying authority described in Condition 14.1a that the person accepts or agrees to be bound by an electronic record executed or adopted with that signature.

15. **Submittals.** Unless otherwise directed by the Department or this permit, the Permittee shall submit reports, compliance certifications, and/or other submittals required by this permit, via the Department's AOS System at http://dec.alaska.gov/applications/air/airtoolsweb using the Permittee Portal option.

    15.1 Alternatively, the documents may be certified in accordance with Condition 14 and submitted either by:

    a. Email under a cover letter using dec.aq.airreports@alaska.gov; or

    b. Certified mail to the following address: ADEC Air Permits Program, ATTN: Compliance Technician, 610 University Ave., Fairbanks, AK 99709-3643.

Section 7 Standard Permit Conditions

16. The Permittee must comply with each permit term and condition. Noncompliance with a permit term or condition constitutes a violation of AS 46.14, 18 AAC 50, and, except for those terms or conditions designated in the permit as not federally enforceable, the Clean Air Act, and is grounds for

    16.1 an enforcement action; or

    16.2 permit termination, revocation and reissuance, or modification in accordance with AS 46.14.280.

17. It is not a defense in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with a permit term or condition.

18. Each permit term and condition is independent of the permit as a whole and remains valid regardless of a challenge to any other part of the permit.

19. The permit may be modified, reopened, revoked and reissued, or terminated for cause. A request by the Permittee for modification, revocation and reissuance, or termination or a notification of planned changes or anticipated noncompliance does not stay any permit condition.

20. The permit does not convey any property rights of any sort, nor any exclusive privilege.

21. The Permittee shall allow the Department or an inspector authorized by the Department, upon presentation of credentials and at reasonable times with the consent of the owner or operator to

    21.1 enter upon the premises where an emissions unit subject to this permit is located or where records required by the permit are kept;

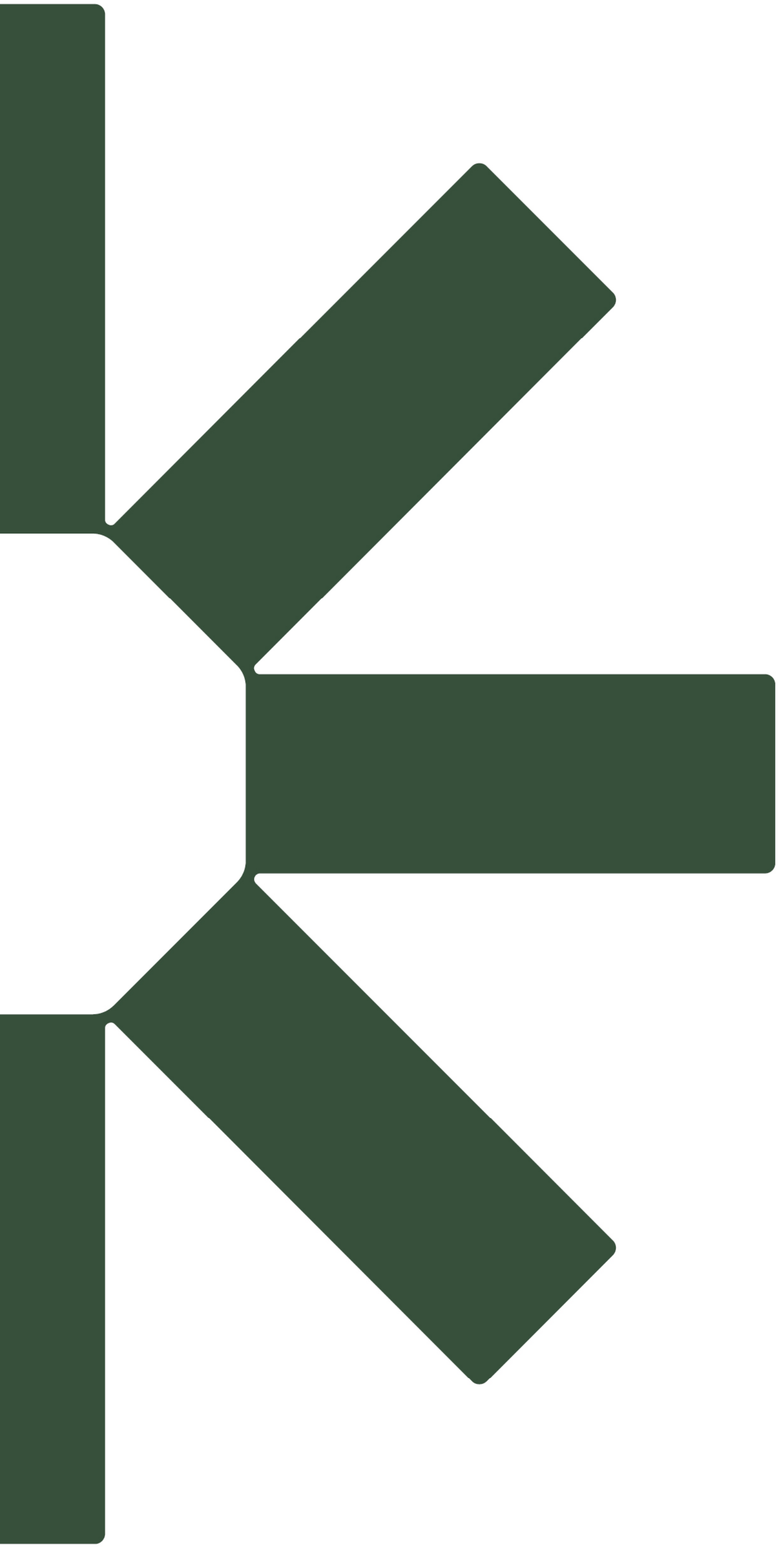
    21.2 have access to and copy any records required by this permit;

    21.3 inspect any stationary source, equipment, practices, or operations regulated by or referenced in the permit; and

    21.4 sample or monitor substances or parameters to assure compliance with the permit or other applicable requirements.

Section 8 Permit Documentation

Date	Document Details
August 13, 2018	Application received
September 7, 2018	Information request sent to Hilcorp Alaska, LLC.
October 16, 2018	Response received from Hilcorp Alaska, LLC regarding information request.
October 30, 2018	Revised application forms received.



Making Sustainability Happen